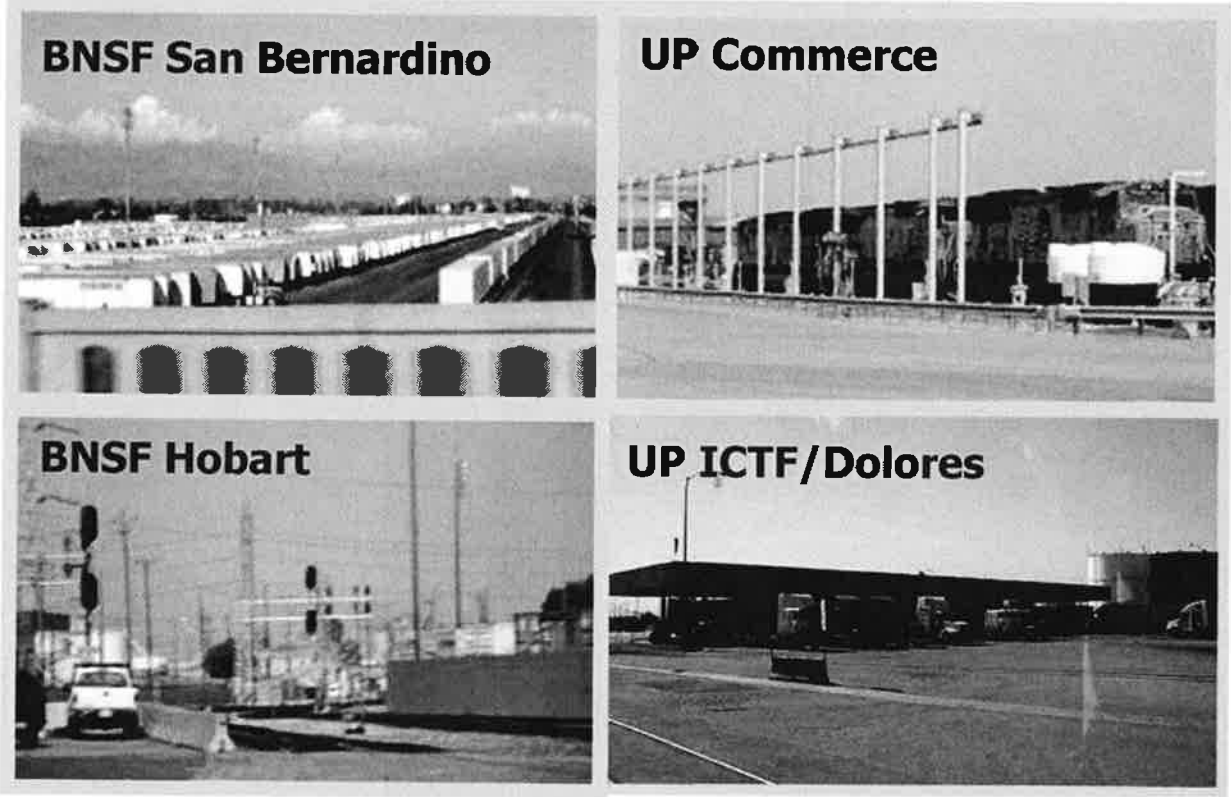
Supplement to the June 2010 Staff Report on

Proposed Actions to Further Reduce Diesel Particulate Matter at High-Priority California Railyards



Note: This report includes the California Environmental Quality Act Functional Equivalent Environmental Document Evaluating the Revised 2010 Commitments Between the Air Resources Board and Union Pacific Railroad and BNSF Railway to Further Reduce Diesel Particulate Emissions at Four High-Priority Railyards. The public comment period on the environmental document closes on August 19, 2011.

July 5, 2011

California Environmental Protection Agency

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AIR RESOURCES BOARD

Supplement to the June 2010 Staff Report on Proposed Actions to Further Reduce Diesel Particulate Matter at High-Priority California Railyards

July 5, 2011

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EXECUTIVE SUMMARY

I. INTRODUCTION

In June 2010, Air Resources Board (ARB or Board) staff released a report entitled *Proposed Actions to Further Reduce Diesel Particulate Matter at High Priority California Railyards* (June 2010 Report) and requested Board approval of set of voluntary, binding agreements with BNSF Railway and Union Pacific (UP) Railroad to reduce emissions of toxic diesel particulate matter (PM) at four railyards in Southern California with high estimated health risks. We refer to these agreements as the 2010 Commitments. The four railyards are the BNSF San Bernardino and Hobart Railyards, and the UP Commerce and ICTF/Dolores Railyards.

On June 24, 2010, the Board considered the June 2010 Report and public comments. At that meeting, the Board adopted Resolution 10-29, which delegated authority to the Executive Officer to approve the 2010 Commitments subject to performance of additional environmental analysis, and suggested that staff, in light of comments received at the hearing, continue to meet with the railroads to strengthen the accountability provisions in the proposed 2010 Commitments. ARB staff met with the railroads, incorporated the suggested additions and posted an interim revised version of the 2010 Commitments on the website on January 7, 2011 for public review.

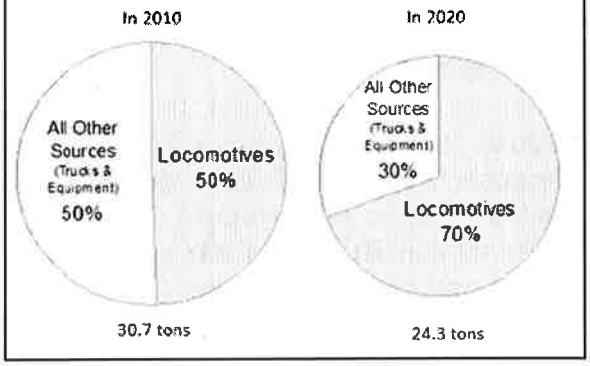
This new document, *Supplement to the June 2010 Staff Report on Proposed Actions to Further Reduce Diesel Particulate Matter at High-Priority California Railyards,* provides updated material. This supplement presents ARB staff's revised estimates of diesel PM emissions and health risk at each railyard. It also includes the latest text of the *Revised 2010 Commitments Between the Air Resources Board and Union Pacific Railroad and BNSF Railway to Further Reduce Diesel Particulate Emissions at Four High-Priority Railyards* ("Revised 2010 Commitments") for each railyard. This report also includes an expanded evaluation of the potential environmental impacts of the Revised 2010 Commitments.

There is a 45-day public comment period for the environmental analysis in Appendix F, which runs from July 5, 2011 to August 19, 2011. Please see the appendix for details on how to submit comments to ARB on this analysis.

The Revised 2010 Commitments would establish enforceable emission caps and other requirements, tracking mechanisms and deadlines to further reduce harmful diesel PM through 2020. The diesel PM emission reduction requirements for each railyard have not changed from the June 2010 proposal. Staff is proposing these voluntary agreements because they are the most effective and most certain way to achieve substantial new diesel PM emission reductions beyond the existing program of regulations and agreements. Any successful effort to secure substantial new reductions must capture the largest sources of railyard diesel PM emissions -- locomotives.

ARB lacks authority to regulate the emissions of late-model or remanufactured locomotives that contribute the majority of the diesel PM emissions at these railyards in future years, as shown in Figure 1. Under the federal Clean Air Act, ARB can regulate only the oldest locomotives, which no longer regularly operate in these four railyards. ARB has already regulated the railyard sources under its direct authority, including drayage trucks, cargo handling equipment, transport refrigeration units, and diesel fuel.

Figure 1
Diesel PM Emissions with Existing Program Only at All Four Priority Railyards Combined



II. UPDATED EMISSIONS AND HEALTH RISK

Appendix A presents ARB staff's updated estimates of the emissions and health risk associated with diesel PM from operations at each railyard. The most significant change was to reflect the actual cargo activity at each railyard in 2010 and to update the projected cargo growth rates for 2011-2020. The changes in cargo activity affect all of the diesel PM emission sources at the railyards. Cargo activity was lower in 2010 than in 2005 at the BNSF San Bernardino, BSNF Hobart, and UP ICTF/Dolores railyards due to the recession. UP Commerce was the only railyard to show a steady increase in cargo activity from 2005 through 2010. Relative to the numbers in the June 2010 Staff Report, the updated emission estimates presented in this supplement reflect the actual 2010 activity and revised growth projections, the cleaner locomotive fleet in operation at these railyards in 2010, and minor improvements in the emissions forecasting methodology.

Table 1 shows the resulting updated diesel PM cancer risk estimates for 2010, as well as revised projections of the cancer risk in future years with implementation of the Revised 2010 Commitments. All yards continue to show a substantial drop in risk between 2005 and 2010 due to the introduction of much cleaner trucks, locomotives, equipment, and fuel in this period. The Revised 2010 Commitments would ensure that emission levels continue to decline even as the freight industry rebounds.

For the three yards that recorded less cargo activity in 2010 than in 2005, the health risks for 2010 are markedly lower than the values presented in the June 2010 Staff Report. Most notable is the decrease in current risk at the highest risk railyard in 2010, 2015, and 2020. For BNSF San Bernardino, the maximum individual cancer risk for 70-year exposure went from 2,500 chances in a million in 2005, down to 650 chances in million in 2010.

Table 1
Updated Reduction in Diesel PM Health Risk with the Revised 2010 Commitments at the Four High-Priority Railyards in Southern California

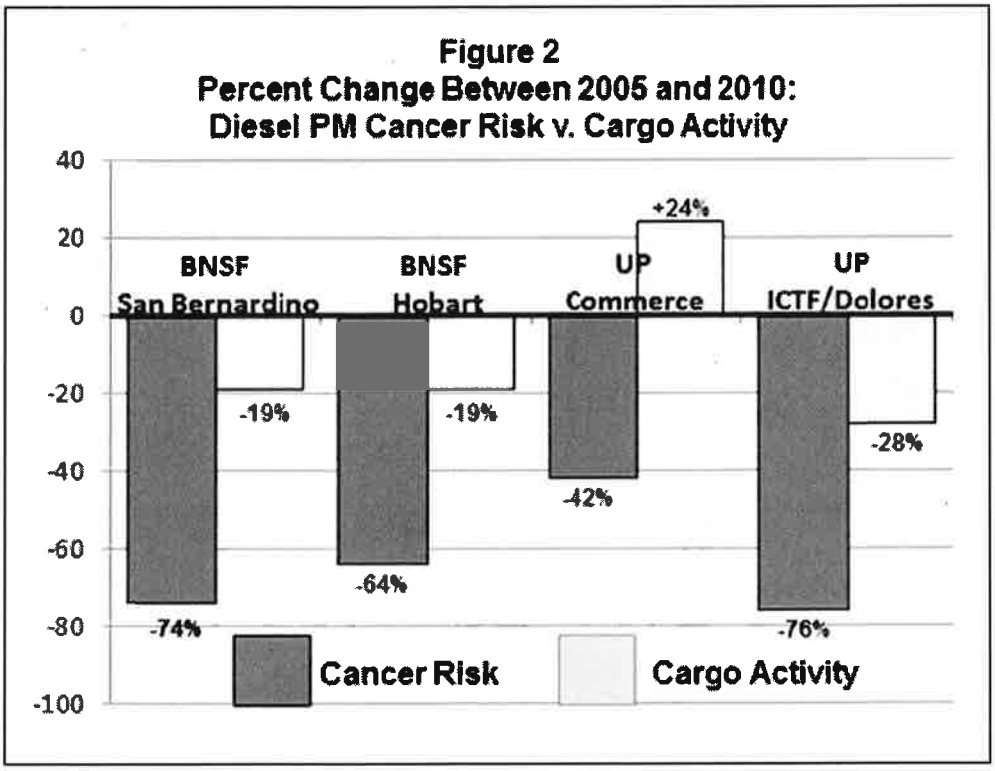
Railyard	Maximum Individual Cancer Risk for 70-Year Exposure* (chances per million)			
	2005	2010	2015	2020
BNSF San Bernardino	2,500	650	500	275
BNSF Hobart	500	180	120	75
UP Commerce	500	290	155	75
UP ICTF/Dolores	800	190	180	120

* Risk estimates for BNSF San Bernardino Railyard consider both the source and location of the diesel PM emissions within the railyard in each year, consistent with the method used to develop the 2005 numbers. For the other railyards, the 2005 and later risk estimates are based on the total diesel PM emissions within each railyard facility.

The key factor in the sharp risk reduction at the BSNF San Bernardino Railyard is the transition of most of the drayage truck fleet to cleaner models by 2010, as required by ARB regulation. The risk estimate for this yard reflects the use of cleaner equipment of all types (including the introduction of several low-emission switch locomotives co-funded by federal and State incentives), a drop in cargo activity from 2005 to 2010, and a more refined technical approach. Consistent with the health risk assessment that generated the 2005 number, ARB staff applied the same methodology that considers both the source and location of diesel PM emissions to estimate the cancer risk in 2010, 2015, and 2020. This means that the diesel PM emission sources that operate closest to where people live (like drayage trucks) have a greater impact on risk and risk reductions than the equipment that operates further away.

The risk at UP Commerce in 2010 is slightly higher than projected in the June 2010 Staff Report (290 in a million now versus 240 in a million previously) because of the steady growth in cargo activity at this yard between 2005 and 2010. This growth means the Revised 2010 Commitments would require the railroad to start achieving additional reductions beyond the existing program *this year* to meet the emissions caps.

Figure 2 compares the reduction in cancer risk versus the change in cargo activity. The recession-induced decline in cargo activity accelerated the reduction in health risk at three of the four yards, but it was not the primary factor. The risk associated with the UP Commerce Railyard also showed a substantial decrease, despite the net increase in cargo activity. The figure illustrates that the significant reduction in health risk between 2005 and 2010 is driven by the introduction of cleaner trucks, equipment, locomotives, and fuel in response to adopted regulations and agreements.



III. LATEST DRAFTS OF REVISED 2010 COMMITMENTS

Appendices B-E include the current drafts of the Revised 2010 Commitments. These are similar to the versions posted on ARB's website on January 7, 2011 that reflected the substantial changes made to the initially proposed versions to strengthen accountability following the June 2010 Board meeting. The primary change between January 2011 and the current versions is to remove the requirements for preparation and submittal of documents in 2011 given the extended timeline to finalize these Revised 2010 Commitments. However, the obligations to reduce diesel PM emissions by specified percentages starting in 2011 remain unchanged, including the 85 percent emission reduction by 2020.

IV. EVALUATION OF POTENTIAL ENVIRONMENTAL IMPACTS

Appendix F is ARB staff's evaluation of the potential environmental impacts of the Revised 2010 Commitments and consideration of potential alternatives. The California Environmental Quality Act (CEQA) and ARB regulations require an analysis to identify any potentially significant adverse environmental impacts of ARB's regulations and projects. ARB has determined that execution and implementation of the proposed Revised 2010 Commitments constitutes a "project" as defined by CEQA. ARB is the lead agency for this project. ARB has prepared the Functional Equivalent Document (FED) in Appendix F in accordance with CEQA and ARB's certified regulatory program.

The objective of the Revised 2010 Commitments is to improve air quality by reducing the emissions of diesel PM from operations at each of the four high priority railyards beyond the benefits of the existing program. The railroads will accelerate the use of cleaner technology, possibly in combination with operational improvements, to achieve the required emission reductions at each railyard.

A. Environmental Impacts

The analysis recognizes the beneficial impacts on emissions and health risk. Compared to the existing program in 2020, the Revised 2010 Commitments would cut the remaining cancer risk from diesel PM by an additional 30-70 percent. They would also reduce the number of people exposed to a cancer risk greater than 10 in a million in 2020 by an additional 80-90 percent beyond the existing program in 2020. Just as the Revised 2010 Commitments will reduce the diesel PM emissions and cancer risk at the railyards, they will also reduce the non-cancer health impacts like cardiac and respiratory illness and premature death.

We used the CEQA Environmental Checklist (Appendix F – Attachment 1) of environmental topics to assess the potential for adverse environmental impacts. With this checklist, staff determined that the proposed project will not involve any changes to the environment that could result in any potentially significant impacts on most of the topic areas. However, staff identified three topics for further review and analysis in the Functional Equivalent Document: aesthetics (light/glare), noise, and transportation and traffic.

Virtually all of the potential adverse environmental impacts identified in the Functional Equivalent Document are directly tied to the possibility of railyard operational changes to reduce emissions or exposure. Community members urged ARB to include requirements in the Revised 2010 Commitments for the railroads to consider operational changes, like moving a truck gate to another area within the railyard. Some of these changes could potentially shift the existing noise, light, or traffic impacts of current railyard activities from one set of nearby residents to another set of residents if operations are relocated within the railyard. It is important to note that the railroads may choose or not choose to implement any of these types of operational changes for any number of reasons.

Staff believes there is a small probability of significant impacts that could result from changes in railyard operations, and it is more likely that changes could result in benefits (e.g., increased efficiency, reduced air pollution). However, in view of the uncertainty about future actions that could potentially affect aesthetics (light/glare), noise, and transportation/traffic, staff took a conservative approach and considered these potential impacts to be potentially significant.

B. Project Alternatives

The purpose of the alternatives analysis is to determine whether or not a variation of the proposed project would reduce or eliminate significant project impacts, within the basic framework of the project objectives. In Appendix F, ARB staff analyzes the potential environmental impacts of four alternatives -- Alternative A: "No Project," Alternative B: an ARB regulation for non-preempted locomotives, Alternative C: an ARB regulation for zero-emission cargo handling equipment at intermodal railyards, and Alternative D: an ARB regulation for railroad risk reduction audits, plans, and measures. ARB staff also discusses a number of alternatives considered but rejected as infeasible and not analyzed.

Each of the four alternatives analyzed would not reduce diesel PM emissions at the four priority railyards as effectively as the proposed project. Alternatives A and B would not satisfy the project objective at all (no further reductions in diesel PM at the four priority railyards). Alternatives C and D would be less effective at meeting the project objective and would involve operational changes that share the same potential environmental impacts with the proposed project, without significantly reducing those impacts.

ARB staff concludes that the proposed project provides the best balance of maximizing the diesel PM emission reductions while minimizing the adverse environmental impacts due to possible operational changes to meet the project objectives.

C. Public Review and Comment

Release of this report starts a 45-day public review period for the Functional Equivalent Document from July 5, 2011 to August 19, 2011. The Functional Equivalent Document in Appendix F provides the information about how to submit comments to ARB.

In accordance with ARB's certified regulatory program, staff will respond in writing to all significant environmental issues raised during this comment period and the ARB Executive Officer will consider those comments and responses prior to final action. After the Executive Officer makes a decision on the proposed project, ARB will post the notice of final action and the written responses to comments on ARB's website and file them with the Secretary of the Natural Resources Agency for public inspection.[1]

[1] Title 17, California Code of Regulations, §60007.

V. STEPS TOWARDS A ZERO- OR NEAR-ZERO EMISSION FREIGHT TRANSPORT SYSTEM

Rail operations are an integral part of a larger freight system and logistics industry in California. The Revised 2010 Commitments, together with existing regulations and agreements, are an important tool to further reduce diesel PM emissions and health risk in communities near the highest risk railyards over the next decade.

Longer-term, we must achieve even greater reductions -- in air toxics to cut the community health risk, in criteria pollutants to meet more health-protective ambient air quality standards, and in greenhouse gases to reduce California's contribution to climate change. To accomplish these objectives, California will need to transition from fossil fuel to cleaner energy sources, including electricity from renewable sources.

Some zero-emission technologies like electric cranes are already available; others like electric drayage and yard trucks are being tested in the field now. While the incremental cost-effectiveness of replacing diesel equipment with 85 percent PM control with electrified equipment is too high to support an ARB regulatory approach today, the railroads may choose to implement this technology in some applications to meet the emission levels in the Revised 2010 Commitments.

ARB is partnering with the South Coast Air Quality Management District to work with the Southern California Association of Governments and stakeholders from the freight industry and affected communities on the longer-term objective -- a more efficient, zero- or near-zero emission freight transport system for Southern California. This initiative is about a coordinated approach to air pollution, energy, transportation, and climate. Our assessment of the potential paths will also need to consider the technical, legal, operational, and financial issues. As the three agencies stated in a recent joint publication:

> *"California can build global competitiveness, create jobs, and improve quality of life by creating a world-class freight transportation system for the 21st century that uses clean technology to swiftly move goods without pollution.*[2]

Concurrent with this new effort on the freight system as whole, there are other activities to encourage development and deployment of advanced technology at the railyards. As directed by the Board, ARB staff will convene a symposium to explore zero- and near-zero emission technology for locomotive and railyard applications. Under the Revised 2010 Commitments, ARB and the railroads would also agree to work collaboratively to develop and implement a formal demonstration program for advanced technology locomotives or other railyard emission sources.

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[2] South Coast Air Quality Management District, Southern California Association of Governments, and California Air Resources Board, *Powering the Future - A Vision for Clean Energy, Clear Skies, and a Growing Economy in Southern California.* 2011.

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Appendix A

Updated Diesel PM Emission and Health Risk Estimates

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Appendix A
Updated Diesel PM Emission and Health Risk Estimates

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Updated Diesel PM Emission and Health Risk Estimates

The June 2010 Staff Report included staff's then-current estimate of the emissions and health risks associated with diesel PM emissions at each of the four priority railyards. Since publication of that report, we have updated the 2010 emissions estimates to reflect actual 2010 cargo activity data, reassessed the potential cargo growth beginning in 2011, and updated our projections of the diesel PM emissions in future years. We also updated the prior estimates of cancer risk and population exposure to diesel PM at each railyard, consistent with the new emission projections. This appendix describes and presents the results of the updated analyses. The diesel PM emissions, cancer risk, and population exposure estimates in this appendix replace and supersede the numbers published in the June 2010 Staff Report. To be consistent with the June 2010 Report, the presentations of the percent change in emissions or risk in this appendix are from the 2005 baseline.

In response to public comments, this appendix also documents the source of the emission inventory numbers for calendar year 2005 used in the June 2010 Staff Report, without modifying those numbers.

This Supplemental Report quantifies the diesel PM emissions from operations at each of the four priority railyards because reducing those emissions and the associated health risk is the purpose of the Revised 2010 Commitments. The actions the railroads would take to implement the Revised 2010 Commitments would provide concurrent reductions in other criteria and toxic air pollutants. ARB staff has not quantified the concurrent reductions in other pollutants because the available, railyard-specific emission inventories were developed for prior Health Risk Assessments and limited to diesel PM.

I. DOCUMENTATION OF BASELINE EMISSIONS OF DIESEL PM IN 2005

The purpose of this section is to more thoroughly document the basis for the 2005 estimates of diesel PM emissions presented in the June 2010 Staff Report and used throughout this Supplemental Report.

In 2005, the ARB entered into a statewide railroad pollution reduction agreement (2005 Agreement) with UP and BNSF; in part, the 2005 Agreement required that Health Risk Assessments (HRAs) be prepared for each of 17 major railyards in the State.[3] Each HRA also included an Emission Inventory (Inventory). In several cases, the original major railyard Inventories or HRAs for 2005 calendar year operations were modified to address changes in ARB emission factors or the calculation of hours of operations for cargo handling equipment, drayage trucks, and transport refrigeration units. These changes were in some cases made early enough to be addressed in the original Inventories or HRAs; in other cases the changes were addressed in subsequent

[3] *ARB/Railroad Statewide Agreement, Particulate Emissions Reduction Program at California Rail Yards*, June 2005.

railyard mitigation plans. Ultimately, all of the changes were reflected in the June 2010 Staff Report, *Proposed Actions to Further Reduce Diesel Particulate Matter at High Priority California Railyards.*[4]

The initial and most significant modification was ARB cargo handling equipment load factors. Originally, ARB had identified the cargo handling equipment load factors to be as high as 70 percent for yard trucks or hostlers, based on test data and operations at various port facilities. However, based on manufacturer data and actual operational hour data from cargo handling equipment at UP ICTF/Dolores Railyards and BNSF Hobart Railyard, ARB determined that the load factors were too high for yard hostlers operating at intermodal railyards. With subsequent ARB/UP/BNSF and industry data, UP and BNSF reduced yard truck load factors to about 20 percent. In intermodal railyards, the revised yard truck load factors were incorporated in subsequent Inventories, HRAs, or mitigation plans.

Other significant changes occurred for railyard drayage trucks and transport refrigeration units. Railyard drayage truck emissions increased with use of an updated emissions model, EMFAC2007 Version 2.30,[5] and the changes were reflected in the railyard mitigation plans. Hours of operation for transport refrigeration units were reduced for the railyard mitigation plans based on subsequent field surveys of railyard transport refrigeration operations. All of the railyard Inventories, HRAs, and mitigation plan documents, with explanations of the cargo handling equipment load factor and drayage truck and transport refrigeration unit adjustments, were made available to the public via list serve notices.

The 2005 Inventories and HRAs included emissions from pass-through passenger locomotives. In developing the 2010 Railyard Commitments, ARB agreed to exempt pass-through passenger locomotive diesel PM emissions. ARB and UP and BNSF determined that passenger locomotive operators would be responsible for mitigating passenger locomotive emissions that occurred in the UP and BNSF high-priority railyards from 2010 to 2020.

The following summary tables (Tables A-1 to A-4) show the calendar year 2005 emissions as stated in the Inventory documents, the updated 2005 emission values as presented in the *June 2010 Staff Report*, and the basis for the updates.

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[4] *June 2010 Staff Report, pp. A1-4, B1-4, C1-4, and D1-4.*

[5] EMFAC2007, Version 2.30, http://www.arb.ca.gov/msei/onroad/downloads/docs/user_guide_emfac2007.pdf

Table A-1
BNSF San Bernardino Railyard
2005 Baseline Emissions of Diesel PM
(tons per year)

Equipment Type	Calendar Year 2005		Basis for Change
	Mitigation Plan*	2010 Railyard Commitments**	
Locomotives - Line Haul - Switch - Service/Testing - Passenger	 6.0 4.0 0.4 0.15	 6.0 4.0 0.4 0.0	Passenger locomotive diesel PM emissions of 0.15 tons per year (tpy) were excluded from railyard emissions in the 2010 Railyard Commitments; passenger locomotive operators are responsible for mitigating these emissions.
Subtotal for Locomotives	*10.6*	*10.4*	
Cargo Equipment	3.6	3.0	Hours of operations were increased and the ARB load factor was reduced for yard hostlers (see discussion preceding this table)
Drayage Trucks	4.4	5.4	Drayage truck diesel PM emissions increased with use of an updated emissions model, EMFAC2007, Version 2.30 (see discussion preceding this table)
Transport Refrigeration Units	3.3	3.3	
Maintenance/Stationary	0.09	0.1	
Total Tons	**22.0**	**22.2**	

* ENVIRON International, *Draft Diesel Particulate Matter Mitigation Plan for the BNSF Railroad San Bernardino Rail Yard*, August 2008, p. 2.
** June 2010 Staff Report, p. A1-4.

Table A-2
BNSF Hobart Railyard
2005 Baseline Emissions of Diesel PM
(tons per year)

Equipment Type	Calendar Year 2005		Basis for Change
	HRA*	2010 Railyard Commitments**	
Locomotives - Line Haul - Switch - Service/Testing - Passenger	 3.2 2.2 0.0 0.5	 3.2 2.2 0.0 0.0	Passenger locomotive diesel PM emissions of 0.5 tpy were excluded from railyard emissions in the 2010 Railyard Commitments; passenger locomotive operators are responsible for mitigating these emissions.
Subtotal for Locomotives	*5.9*	*5.4*	
Cargo Equipment	4.2	5.9	Hours of operations were increased and the ARB load factor was reduced for yard hostlers (see discussion preceding Table A-1)***
Drayage Trucks	10.1	10.7	Drayage truck diesel PM emissions increased with EMFAC2007, Version 2.30 (see discussion preceding Table A-1)***
Transport Refrigeration Units	3.6	2.1	Hours of operation were reduced based on subsequent field equipment surveys***
Maintenance/Stationary	0.1	0.1	
Total Tons	**23.9**	**24.2**	

* Health Risk Assessment for the BNSF Railway Hobart Railyard, November 2007, p. 10.
** June 2010 Staff Report, p. B1-4.
*** ENVIRON International, *Diesel Particulate Matter Mitigation Plan for the BNSF Railroad Hobart Rail Yard*, September 2008, p. 10.

Table A-3
UP Commerce Railyard
2005 Baseline Emissions of Diesel PM
(tons per year)

Equipment Type	Calendar Year 2005		Basis for Change
	HRA*	2010 Railyard Commitments**	
Locomotives			No changes made
- Line Haul	1.3	1.3	
- Switch	1.9	1.9	
- Service/Testing	1.7	1.7	
- Passenger	-	-	
Subtotal for Locomotives	*4.9*	*4.9*	
Cargo Equipment	4.8	4.8	
Drayage Trucks	2.0	2.0	
Transport Refrigeration Units	0.3	0.3	
Maintenance/Stationary/Heavy	0.1	0.1	
Total Tons	**12.1**	**12.1**	

* ARB, *Health Risk Assessment for the Union Pacific Railroad Commerce Railyard*, November 2007, p. 12.
** June 2010 Staff Report, p. C1-4.

Table A-4
UP ICTF/Dolores Railyards
2005 Baseline Emissions of Diesel PM
(tons per year)

Equipment Type	Calendar Year 2005		Basis for Change
	HRA*	2010 Railyard Commitments**	
Locomotives - Line Haul - Switch - Service/Testing - Passenger	 3.0 5.6 1.2 0.0	 1.2 5.6 1.2 0.0	UP Modernization Plan accounted for 1.8 tpy of Alameda Corridor locomotive emissions generated 0.5 mile outside of the UP ICTF/Dolores Railyards***. These emissions were excluded from the 2005 HRA and 2010 Commitments**
Subtotal for Locomotives	*9.8*	*8.0*	
Cargo Equipment	4.8	4.8	
Drayage Trucks	7.5	5.9	UP Modernization Plan accounted for 1.6 tpy of drayage truck diesel PM emissions generated 0.5 mile outside of the UP ICTF/Dolores Railyards***. These emissions were excluded from the 2005 HRA and 2010 Commitments**
Transport Refrigeration Units	1.5	1.5	
Maintenance/Stationary	0.06	0.06	
Total Tons	**23.7**	**20.3**	

* ARB, *Health Risk Assessment for the UP Intermodal Container Transfer Facility (ICTF) and Dolores Railyards*, April 2008, p. 10.
** June 2010 Staff Report, p. D1-4.
*** *Application for Development Project Approval, Intermodal Container Transfer Facility (ICTF) Modernization Project* (December 26, 2007), p. 64.

II. UPDATED DIESEL PM EMISSIONS FOR 2010 – 2020

In the June 2010 Staff Report, ARB staff developed diesel PM emissions estimates for 2010 through 2020 by applying emission control factors based on existing U.S. EPA and ARB regulations and agreements (i.e., the 1998 Agreement[6] and the 2005 Agreement[7]) to activity held constant at 2005 levels. ARB staff has now updated these emission estimates to reflect reported activity for 2010 and projected growth rates from 2011-2020 for each of the four high-priority railyards.

Section A describes the cargo activity at each yard through 2010 and the basis for the projected growth from 2011-2020. ARB staff looked at activity and operations at each railyard from 2005 through 2010, and estimated an annual growth rate for each railyard from 2011 through 2020.

Section B presents a detailed discussion of the emission control factors for each type of equipment operating at the railyards, reflecting the benefits of adopted regulations, as well as prior agreements between ARB and the railroads.

Finally, in Section C, we present tables for each railyard showing updated estimates of the diesel PM emissions in 2010 and projections for 2015-2020, as well as updated estimates of the excess cancer risk and population exposure. In each case, we show projections for the existing program of adopted regulations and agreements, and the existing program plus the Revised 2010 Commitments.

A. Basis for Growth Rates

Tables A-5 and A-6 below show the data that staff used on actual operational activity levels from 2005 to 2010, and the basis for estimating future activity levels from 2011 to 2020.

Activity levels for 2005 and 2010 were based on actual container lifts at each of the four high-priority railyards. Over this time period, the number of lifts increased at UP Commerce, but decreased at the other three railyards. Forecasts for 2015 and 2020 are based on various assumed annual average growth rates from actual 2010 lift levels: 5.5 percent for international containers, based on the San Pedro Bay Ports' international container forecast of 5.5 percent average annual growth;[8] 4.1 percent for domestic containers, based on ARB's amended on-road truck and bus rule, which assumed a 4.1 percent average annual growth rate;[9] or a proportionate combination of both.

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[6] ARB, *Memorandum of Mutual Understandings and Agreements, South Coast Locomotive Fleet Average Emission Program*, July 1998.

[7] *ARB/Railroad Statewide Agreement, Particulate Emissions Reduction Program at California Rail Yards*, June 2005.

[8] Tioga Group, Inc., *San Pedro Bay Container Forecast Update*, July 2009, p. 3.

[9] *Emissions Analysis Methodology and Results Medium-Heavy Duty Diesel Trucks, Heavy-Heavy Duty Diesel Trucks, and Regulated Bus Categories*, Proposed Amendments to the Truck and Bus Regulation, the Drayage Truck Regulation and the Tractor-Trailer Greenhouse Gas Regulation, October, 2010. http://www.arb.ca.gov/regact/2010/truckbus10/truckbus10isor.pdf

Table A-5
Four High-Priority Railyards
Container Lift Activities, Forecasts, and Capacities
(April 2011)

Railyard	2005 (lifts) Actual	2010 (lifts) Actual	2015 (lifts) Projected	2020 (lifts) Projected	Annual Percent Growth from 2011 to 2020	Railroad Stated Capacity (lifts)
BNSF San Bernardino	555,000[a]	447,000[c]	546,000	668,000	4.1	660,000[e]
% change from 2005	--	-19%	-1.6%	+20%	--	--
BNSF Hobart	1,338,000[a]	1,090,000[c]	1,386,000	1,763,000	4.9	1,500,000[e,f]
% change from 2005	--	-19%	+3.6%	+32%	--	--
UP Commerce	345,000[b]	429,000[d]	534,000	664,000	4.4	510,000[e]
% change from 2005	--	+24%	+55%	+92%	--	--
UP ICTF/Dolores	626,000[b]	450,000[d]	587,000	767,000	5.5	760,000[e]
% change from 2005	--	-28%	-6.2%	+23%	--	--

a. Del Grosso, Robert C., *BNSF Railway Company 2010 Locomotive Review*, p. 9.
b. Union Pacific Fact Book, 2005, p. 9.
c. ARB staff, Harold Holmes, Personal communication with BNSF via email (January 17, 2011).
d. Union Pacific Fact Book, 2010, p. 15.
e. Los Angeles County Metropolitan Transportation Authority, *Technical Memorandum – I-710 Railroads Goods Movement Study, WBS Task ID:160.10.50*, February 2009, pp. 22-24.
f. Based on personal communications between BNSF and Harold Holmes via phone on May 20, 2011, staff determined that 1.5 million of 1.7 million lift capacity was attributed to BNSF Hobart Railyard only, with the balance attributed to BNSF Commerce/Eastern Railyard.

Based on the estimated rates of growth from 2011-2020, staff acknowledges that the projected railyard lift volumes equal or exceed the stated railyard lift capacities by 2020 or earlier. Staff understands that railyard lift capacities can fluctuate slightly or can be adjusted operationally (e.g., higher stacking of containers), at least on a short-term basis. Acknowledging the potential for short-term operational adjustments and the uncertainty in defining the absolute capacity of a railyard, staff chose to be protective of public health by assuming that the forecast rates of growth of container lift volumes would continue, even if the projected lift volumes equaled or exceeded stated railyard lift capacities. The Revised 2010 Commitments would cap future year emissions, regardless of the actual growth experienced.

Table A-6 shows the split between international and domestic containers handled at each yard. This split provided the basis for applying different growth rates to each type of container activity.

Table A-6
UP and BNSF Intermodal Off-Dock Railyards
In the South Coast Air Basin
International vs. Domestic Containers

Railyard	International Containers (Port Containers)[a]	Domestic Containers (Non-Port / Warehouse / Transloading)[a]
BNSF San Bernardino	0%	100%
BNSF Hobart (includes BNSF Commerce/Eastern)	59%	41%
UP Commerce	24%	76%
UP ICTF/Dolores	100%	0%

a. Los Angeles County Metropolitan Transportation Authority, *Technical Memorandum – I-710 Railroads Goods Movement Study, WBS Task ID:160.10.50*, February 2009, pp. 22-24.

B. Basis for Emission Control Factors

ARB staff employed a number of resources to estimate diesel PM emission control factors. The emission control factors for the Revised 2010 Commitments are provided below. For switch locomotives, the control factor from the June 2010 Staff Report was increased from 75 percent to 85 percent. Detailed explanations of the bases for all the control factors are provided later in this section. The control factors from Table A-7 are multiplied by the railyard diesel PM emissions, which have been recalculated for the Revised 2010 Commitments to incorporate the annualized growth rates from 2011-2020, to derive the updated railyard diesel PM emission estimates as shown in Tables A-10, A-14, A-18, and A-22.

Table A-7
Emission Control Factors by Source Category, Relative to 2005 Emissions
(With Existing U.S. EPA and ARB Regulations and Agreements)

EMISSION SOURCE CATEGORY	2010	2015	2020
Locomotives:			
Line Haul	25%[1]	30%[2]	35%[2]
Switch[3]	85%	85%	85%
Service/Testing	25%	30%	35%
Non-Locomotive:			
Cargo Handling Equipment	50%	80%	90%
Heavy-Duty Diesel Drayage Trucks	80%	85%	90%
Transport Refrigeration Units	50%	70%	90%

[1] In-use emission levels for line haul locomotives in lower power settings (i.e., primarily idle, Notch 1, Notch 2): difference between Tier 0 (assumed 2005 average) and Tier 2 (2010 average, per 1998 Agreement).

[2] In-use emission levels for line haul locomotives in lower power settings (i.e., primarily idle, Notch 1, Notch 2): per U.S. EPA locomotive rulemaking in 2008, 50 percent of Tier 2's remanufactured to Tier 2+/Tier 3 by 2015, with a Tier 3 PM locomotive fleet average achieved by 2020.

[3] Diesel PM emission level of Tier 3 gen-set switch locomotives is about 85 percent lower than the older switch locomotives that they replace (i.e., 0.72 g/bhp-hr in-use to ≤ 0.1 g/bhp-hr PM).

The following discussion presents the basis for the railyard diesel PM emission control factors.

1. Locomotive Emissions

In 2005, the average line haul locomotive diesel PM emissions in the eighteen designated railyards were assumed to be approximately equivalent to the Tier 0 in-use PM emission level of about 0.32 g/bhp-hr.[10] The line haul locomotive emission reductions in railyards are estimated at about 25 percent in 2010, 30 percent in 2015, and 35 percent in 2020 based on collected American Association of Railroads in-use emission testing data in the lower power settings (Table A-7 notes).

Table A-8 shows the federal locomotive emission standards in grams of pollutant per brake horsepower-hour (g/bhp-hr) and the associated percent reduction compared to uncontrolled, pre-Tier 0 emission levels, for oxides of nitrogen (NOx), PM, and hydrocarbons (HC). As the railroads replace older locomotives or upgrade the engines in those locomotives to Tier 4 levels to meet the diesel PM levels in the Revised 2010

[10] U.S. EPA Technical Highlights, EPA 420-F-97-051, December 1997.

Commitments, those actions will simultaneously reduce PM, NOx, and HC by about 90 percent over pre-Tier 0 levels.

a. Line Haul Locomotives

The 2005 railyard diesel PM Inventories and HRAs assumed a line haul locomotive fleet average roughly equivalent to a Tier 0 emission level. Generally, the baseline assumed that the line haul locomotive fleet was dominated by Tier 0 line haul locomotives (built in 2000 and 2001). The baseline also assumed that pre-Tier 0 locomotives offset emission benefits from newer Tier 1 (built from 2002-2004) and the few new Tier 2 locomotives (production began in 2005) that had begun to penetrate the fleet in 2005.

ARB staff assumed that the line haul locomotive fleet operating in the South Coast Air Basin would be equivalent to a Tier 2 emission level by January 1, 2010, pursuant to the 1998 Locomotive NOx Fleet Average Agreement. In initially reviewing the Inventories, ARB staff assumed that Tier 2 locomotives would provide a 50 percent PM control factor over the baseline (i.e., over a Tier 0 emission level). The 50 percent PM control factor was the difference between the U.S. EPA pre-Tier 0/Tier 0 in-use PM emission level of 0.32 g/bhp-hr and a Tier 2 in-use PM emission level of 0.16 g/bhp-hr. However, these emission levels and the related control factors were calculated over the whole line haul duty cycle.

The line haul locomotive emission standards developed by the U.S. EPA are based on the entire line haul locomotive duty cycle, which assumes a percentage of time in each of a locomotive's 11 settings – i.e., idle (low and normal), dynamic brake and eight power or notch (Notch 1-8) settings.[11] This is significant because diesel fuel consumption rates have a large impact on locomotive emissions, and fuel consumption is greater in the highest power settings (i.e., Notches 5 through 8) than in the lower power settings (i.e., idle and Notches 1 through 4). For example, a line haul locomotive consumes about 5 gallons per hour in the idle setting (the lowest power setting) and about 200 gallons per hour (or more) in Notch 8 (the highest power setting). The duty cycle assumes that a line haul locomotive will be in the idle and dynamic brake settings at about 50 percent of the time, in Notches 1 through 4 at about 23 percent of the time, and in Notches 5 through 8 at about 27 percent of the time. Consequently, to meet the U.S. EPA line haul locomotive standards, line haul locomotives are designed to achieve the greatest amount of emission reductions in the highest power settings (i.e., Notches 5 through 8).

[11] Title 40, Code of Federal Regulations, Part 92.132, a(ii).

Table A-8
Federal Locomotive Emission Standards and Percent Control[12,13]

Line Haul Locomotives							
Emission Tier	Year of Manufacture	NOx		PM		HC	
		Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control
Pre-Tier 0	1973-1999	13.5*	n/a	0.6**	n/a	1.0	n/a
Tier 0	2000-2001	9.5	30	0.6	0	1.0	0
Tier 1	2002-2004	7.4	45	0.45	25	0.55	45
Tier 2	2005-2011	5.5	59	0.2	67	0.3	70
Tier 3	2012-2014	5.5	59	0.1	83	0.3	70
Tier 4	2015	1.3	90	0.03	95	0.14	86
Switch Locomotives							
Emission Tier	Year of Manufacture	NOx		PM		HC	
		Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control
Pre-Tier 0	1973-1999	17.4*	n/a	0.72**	n/a	2.1	n/a
Tier 0	2000-2001	14.0	20	0.72	0	2.1	0
Tier 1	2002-2004	11.0	37	0.54	25	1.2	43
Tier 2	2005-2011	8.1	53	0.24	67	0.6	71
Tier 3	2012-2014	5.0	71	0.1	86	0.6	71
Tier 4	2015	1.3	93	0.03	96	0.14	93

* U.S. EPA Locomotive Emissions Standards – Regulatory Support Document – p. 96 – Estimated NOx Emission Rates.
** ARB staff assumed older pre-Tier 0 line haul and switch locomotives would be able to emit up to the Tier 0 PM emission standards, based on American Association of Railroads in-use emission testing (required to comply with U.S. EPA in-use emission testing requirements)for older switch locomotives with EMD 645 engines.

Based on the Inventories and HRAs, and further discussions with UP and BNSF and locomotive manufacturers, ARB staff determined that line haul locomotives spend nearly all of their operational time within railyards in either idle, Notch 1, or Notch 2. Subsequent U.S. EPA in-use line haul locomotive emission testing determined that Tier 2 line haul locomotives were reducing PM emissions by about 25 percent in the lower line haul power settings, rather than 50 percent over the whole line haul duty cycle. As a result, ARB staff adjusted the level of the PM control factor for line haul locomotives to 25 percent for Tier 2 locomotives – the assumed fleet average in the South Coast Air Basin in 2010.

ARB staff also adjusted the level of PM control factor for Tier 3 locomotives to 35 percent, and the level of PM control factor for Tier 4 locomotives to 45 percent. The

[12] Title 40, Code of Federal Regulations, Part 1033.101, a.
[13] U.S. EPA Fact Sheet EPA-420-F-09-025, April 2009.

Tier 3 and Tier 4 PM control factors are conservative estimates, based largely on the differences between Tier 2 and Tier 0 line haul locomotives in the lower power settings, with some additional small incremental reductions. Staff will revise these numbers as actual emissions testing results become available for new Tier 3 and Tier 4 line haul locomotives. U.S. EPA locomotive regulations (Title 40, Code of Federal Regulations, Part 1033.101) require Tier 3 line haul locomotives to be built beginning in 2012 and Tier 4 line haul locomotives to be built beginning in 2015.

b. Switch (Yard) Locomotives

The U.S. EPA switch locomotive duty cycle assumes switch locomotives are in the idle setting about 60 percent of the time, and a significant part of the remaining time in the lower notch settings (Notches 1 through 4). For switch locomotives, the greatest levels of diesel fuel consumption and PM emissions occur in the lower power settings (i.e., the idle setting and Notches 1 through 4). Consequently, to meet the U.S. EPA switch locomotive emissions standards, switch locomotive engines are designed to achieve the greatest proportionate amount of emission reductions in the lower power settings.

The switch locomotive PM control factor in the June 2010 Staff Report compared the U.S. EPA suggested in-use switch locomotive in-use PM emission level of 0.44 g/bhp-hr to the ARB-verified ultra-low switch locomotive PM emission level of 0.1 g/bhp-hr, thereby assuming a reduction of about 75 percent. This control factor was based on a pre-Tier 0/Tier 0 fleet average for switch locomotive operations in the South Coast Air Basin used in the railyard Inventories and HRAs for the 2005 calendar year.

In 1998, U.S. EPA assumed EMD two-stroke switch locomotive in-use PM emission levels to average about 0.44 g/bhp-hr, with reported in-use PM emission levels ranging from 0.22 to 0.86 g/bhp-hr.[14] However, from 2005 to 2009 the American Association of Railroads (AAR) performed U.S. EPA in-use emission testing, which included older EMD switch locomotives (e.g., EMD GP15 and GP/SD38) powered with older EMD 645 engines. These older switch locomotives produced a range of PM emission levels between 0.4 and 0.6 g/bhp-hr. Further, staff recognized that under the U.S. EPA locomotive regulations (Title 40, Code of Federal Regulations, Parts 92 and 1033), any pre-Tier 0 switch locomotive remanufactured to meet the U.S. EPA Tier 0 PM emission standard, was allowed to emit in-use up to 0.72 g/bhp-hr. Therefore, for the Revised 2010 Commitments, staff revised the control factor for switch locomotives: staff compared the U.S. EPA Tier 0 switch locomotive emission standard of 0.72 g/bhp-hr to the ARB-verified ultra-low switch locomotive PM emission level of 0.1 g/bhp-hr, and thus assumed a control factor of 85 percent.

In 2005, the four high-priority railyards were supported primarily by older pre-Tier 0, and a few remanufactured Tier 0 switch locomotives. At the time, Electro-Motive Diesel (EMD) and General Electric (GE), the two largest line haul locomotive manufacturers, had not produced any new switch locomotives since 1987,[15] largely due to the

[14] U.S. EPA Technical Highlights, EPA 420-F-97-051, December 1997.
[15] http://www.american-rails.com/emd-sw8.html. Web archive, May 13, 2011.

oversupply of switch locomotives resulting from consolidation and mergers of numerous railroads in the United States in the late 1980's and 1990's.

In 2007 and 2008, UP acquired 61 ARB-verified ultra-low emitting generator set (gen-set) switch locomotives. As a result, both the UP ICTF/Dolores Railyards and the UP Commerce Railyard have been nearly fully supported by gen-set switch locomotives since 2008. In 2010, BNSF acquired 11 gen-set switch locomotives through federal incentive funding, and assigned six gen-set switch locomotives to the BNSF Hobart Railyard, three gen-set switch locomotives to the BNSF San Bernardino Railyard, and two other gen-set switch locomotives to the BNSF Watson Railyard (a smaller railyard near the Ports of Los Angeles and Long Beach). In 2010-2011, BNSF also contracted through federal and State incentive funding programs to assign six more gen-set switch locomotives to the BNSF San Bernardino Railyard by 2012-13. As a result, staff has updated the railyard diesel PM emission estimates to include the gen-set switch locomotives that are currently operating or will be operating in the BNSF San Bernardino Railyard. Staff has also included the railyard diesel PM emission reductions from the six gen-sets currently operating at the BNSF Hobart Railyard. Staff assumes these railyard diesel PM emission reductions will occur by no later than 2015.

c. Locomotive Service and Testing Emissions

ARB staff assumed that locomotive service and testing emissions would be dominated by and consistent with the South Coast Air Basin line haul locomotive fleet emissions. As a result, the service and testing operations realize the same levels of diesel PM emissions reductions as the line haul locomotives in Table A-7.

2. Cargo Handling Equipment Emissions

Emission reductions for cargo handling equipment that operated at the four high-priority railyards were largely based on the ARB *Cargo Handling Equipment at Ports and Intermodal Railyards Regulation* (Cargo Handling Equipment Regulation). In developing the cargo handling equipment emission reductions, ARB staff calculated the changes in railyard cargo handling equipment PM emissions from 2005 through 2009, and the total changes to railyard cargo handling equipment PM emissions levels with new equipment (or equipment retrofitted with a diesel particulate filter) from the 2005 baseline through 2020.

Under the ARB Cargo Handling Equipment Regulation, cargo handling equipment operating within these facilities will meet Tier 4 PM emission standards (0.01 g/bhp-hr) and provide a 90 percent or greater reduction in cargo handling equipment PM emissions by 2020. ARB staff analysis of the Cargo Handling Equipment Regulation, railyard Inventory data, and railyard HRA data showed that cargo handling equipment diesel PM emissions at the railyards would be reduced by about 50 percent by 2010, and by about 80 percent by 2015.

ARB staff analysis applied the Cargo Handling Equipment Regulation to equipment counts for 2005 and 2009 at the BNSF San Bernardino Railyard, based on railyard Inventory and HRA data as well as regulatory compliance plans from BNSF. Using this information, along with communications with BNSF, ARB staff analyzed and forecast compliance dates for individual pieces of cargo handling equipment at this railyard. ARB staff's analysis revealed that changes in emissions had already occurred or would occur earlier than forecast by the ARB Cargo Handling Equipment Regulation, and would result in cargo handling equipment PM emission reductions from 2005 levels greater than 90 percent. In 2005 and 2009, the BNSF San Bernardino Railyard had 58 yard hostlers and 13 cranes. Based on ARB staff's analysis, we conclude that every yard hostler, crane, and related cargo handling equipment operating within the railyard will achieve Tier 4 PM emission levels no later than 2015, either by retrofitting older pieces of equipment or replacing them with new ones.

3. Heavy Duty Truck Emissions

Emission reductions for heavy-duty diesel drayage trucks that operate within the four high-priority railyards were based on the ARB Drayage Truck regulation. The ARB Drayage Truck regulation mandates that all drayage trucks entering ports and intermodal railyards meet the U.S. EPA 2007 PM emission standard of 0.01 g/bhp-hr for new Class 8 trucks (>33,000 lbs).

ARB staff analysis of the Drayage Truck Regulation, railyard Inventories, and railyard HRAs revealed that drayage truck diesel PM emissions at the four high-priority railyards would be reduced by about 80 percent in 2010, 85 percent in 2015, and 90 percent in 2020. .

Heavy-duty diesel truck and drayage truck emission estimates in the railyard Inventories and HRAs were based on ARB's EMFAC emission model. This model provided fleet composition and emission estimates for truck activity (based on speed and distance) that occurred within each railyard.

4. Transport Refrigeration Unit Emissions

Emission reductions for transport refrigeration units (TRUs) operating at the four high-priority railyards were based on the ARB air toxics control measure (ATCM) for TRUs. This ATCM has a phased-in compliance schedule, based on model year. ARB staff analysis of the ATCM for TRUs, railyard Inventories, and railyard HRAs showed that TRU diesel PM emissions at the railyards would be reduced by about 50 percent in 2010 and by about 70 percent in 2015. By 2020, this measure is estimated to provide about a 90 percent or greater reduction in diesel PM emissions from TRU truck and railcar engines in intermodal railyards.

Emission estimates in the railyard Inventories and HRAs were based on ARB's EMFAC emission model. This model provided fleet composition and emission estimates for TRU activity (based on horsepower and time) that occurred within each railyard. Under

the ATCM, every TRU operating in a railyard, under any current or proposed phase-in schedule, must meet a PM emission level of 0.01 g/bhp-hr by 2020.

5. Stationary Compression Ignition Engine and Maintenance of Way Equipment Emissions

ARB staff estimates the stationary sources will continue to contribute a small portion of diesel PM emissions at each of the four high-priority railyards – typically 0.1 ton per year or less.[16] However, most of this equipment has been upgraded since 2005 to U.S. EPA Tier 2 or 3 PM emission standards. Staff estimates that this equipment could be replaced or retrofitted to meet U.S. EPA Tier 4 non-road engines standards by as early as 2020, representing up to a 90 percent or more reduction of PM emissions, for a reduction from 0.1 to 0.01 tons per year.

C. Updated Diesel PM Emissions and Health Risks with the Revised 2010 Commitments

In this section, staff presents updated tables reflecting projected diesel PM emissions for each of the four high-priority railyards and the additional emission reductions achieved by the Revised 2010 Commitments.

For each of four high-priority railyards, there are three updated tables. The first presents the revised estimates of diesel PM emissions based on actual 2010 cargo activity, projected cargo growth in 2011-2020, and an updated accounting of newly introduced gen-set switch locomotives. The next tables show the corresponding updated cancer risk and population exposed to a risk above 10 in a million at each railyard.

[16] *June 2010 Staff Report*, pp. A1-4, B1-4, C1-4, and D1-4.

1. BNSF San Bernardino

Table A-9
BNSF San Bernardino Railyard
Updated Estimated Diesel PM Emissions by Equipment Type
(tons per year)

Equipment Type	2005	2010	2015	2020
Emissions with Existing Program Only				
Freight Locomotives				
- Line Haul	6.0	3.6	4.1	4.7
- Switch *	4.0	2.7	0.6	0.7
- Service/Testing	0.4	0.2	0.3	0.3
Subtotal for Locomotives	*10.4*	*6.5*	*5.0*	*5.7*
Cargo Equipment	3.0	1.2	0.6	0.4
Drayage Trucks	5.4	0.9	0.8	0.7
Transport Refrigeration Units	3.3	1.3	1.0	0.4
Maintenance/Stationary	0.1	0.1	0.1	0.1
Subtotal for Other Equipment	*11.8*	*3.5*	*2.5*	*1.6*
Total Tons	**22.2**	**10.0**	**7.5**	**7.3**
Reduction (%) from 2005	N/A	55%	66%	67%
Emissions with Existing Program plus Revised 2010 Commitments				
Additional Emission Reductions with Commitments	N/A	N/A	-0.4	-3.9
Tons Remaining	**22.2**	**10.0**	**7.1**	**3.4**
Reduction (%) from 2005	N/A	55%	68%	85%
Additional Reduction (%) Attributable to the Commitments in Future Years	N/A	N/A	**5%**	**53%**

Table A-10
BNSF San Bernardino Railyard
Updated Estimated Maximum Individual Cancer Risk

	Excess Maximum Individual Cancer Risk for 70-Year Exposure* (chances in a million)			
	2005	**2010**	**2015**	**2020**
Existing Program	2,500	650	510	400
Existing Program + Commitments	N/A	650	500	275
Total Reduction (%) from 2005 Due to Existing Program + Commitments	N/A	74%	80%	89%

* Estimated cancer risk considers the source and location of the diesel PM emissions within the railyard.

Table A-11
BNSF San Bernardino Railyard
Updated Estimated Population Exposure to Excess Cancer Risk Greater than 10 in a Million

	Number of People Exposed			
	2005	**2010**	**2015**	**2020**
Existing Program	350,000	187,000	140,000	137,000
Existing Program + Commitments	N/A	187,000	135,000	69,000
Total Reduction (%) from 2005 Due to Existing Program + Commitments	N/A	47%	61%	80%

For BNSF San Bernardino, if you compare the rate of reduction in cancer risk over time (Table A-10) to the rate of reduction in diesel PM emissions (Table A-9), you will notice that risk decreases faster than emissions in the earlier years and slower in the out years. This is because the diesel PM emission sources that achieved substantial reductions by 2010 are also the emission sources with the greatest impact on health risk because of their proximity to nearby residents. The proximity and emission density of the BNSF San Bernardino Railyard truck gate to residents living about 100 feet away led to a highly elevated cancer risk estimate for 2005. By 2010, drayage trucks, cargo handling equipment, and transport refrigeration units had achieved the significant emission reductions required by ARB regulations, triggering a greater than proportional

reduction in health risk. In later years, more of the reductions will come from locomotives that operate further from residents. As a result, locomotives will yield less risk reduction per unit of emission reductions than we saw for drayage trucks.

2. BNSF Hobart

Table A-12
BNSF Hobart Railyard
Updated Estimated Diesel PM Emissions by Equipment Type
(tons per year)

Equipment Type	2005	2010	2015	2020
Emissions with Existing Program Only				
Freight Locomotives				
- Line Haul	3.2	2.0	2.3	2.8
- Switch	2.2	1.7	1.0	1.2
- Service/Testing	0	0	0	0
Subtotal for Locomotives	*5.4*	*3.7*	*3.3*	*4.0*
Cargo Handling Equipment	5.9	2.4	1.2	0.8
Drayage Trucks	10.7	1.7	1.7	1.4
Transport Refrigeration Units	2.1	0.9	0.7	0.3
Maintenance/Stationary	0.1	0.1	0.1	0.1
Subtotal for Other Equipment	*18.8*	*5.1*	*3.7*	*2.6*
Total Tons	**24.2**	**8.8**	**7.0**	**6.6**
Reduction (%) from 2005	N/A	64%	71%	73%
Emissions with Existing Program plus Revised 2010 Commitments				
Additional Emission Reductions with Commitments	N/A	N/A	-1.2	-3.0
Tons Remaining	**24.2**	**8.8**	**5.8**	**3.6**
Reduction (%) from 2005	N/A	64%	76%	85%
Additional Reduction (%) Attributable to the Commitments in Future Years	N/A	N/A	**17%**	**45%**

Table A-13
BNSF Hobart Railyard
Updated Estimated Maximum Individual Cancer Risk

	Excess Maximum Individual Cancer Risk for 70-Year Exposure (chances in a million)			
	2005	**2010**	**2015**	**2020**
Existing Program	500	180	145	140
Existing Program + Commitments	N/A	180	120	75
Total % Reduction from 2005 Due to Existing Program + Commitments	N/A	64%	76%	85%

Table A-14
BNSF Hobart Railyard
Updated Estimated Population Exposure to Excess Cancer Risk Greater than 10 in a Million

	Number of People Exposed			
	2005	**2010**	**2015**	**2020**
Existing Program	848,000	281,000	240,000	223,000
Existing Program + Commitments	N/A	281,000	192,000	110,000
Total % Reduction from 2005 Due to Existing Program + Commitments	N/A	67%	77%	87%

3. UP Commerce

Table A-15
UP Commerce Railyard
Updated Estimated Diesel PM Emissions by Equipment Type
(tons per year)

Equipment Type	2005	2010	2015	2020
Emissions with Existing Program Only				
Freight Locomotives				
- Line Haul	1.3	1.2	1.4	1.6
- Switch	1.9	0.4	0.4	0.6
- Service/Testing	1.7	1.6	1.8	2.1
Subtotal for Locomotives	*4.9*	*3.2*	*3.6*	*4.3*
Cargo Equipment	4.8	3.0	1.5	0.9
Drayage Trucks	2.0	0.5	0.5	0.4
Transport Refrigeration Units	0.3	0.2	0.1	0.03
Maintenance/Stationary	0.1	0.1	0.2	0.2
Subtotal for Other Equipment	*7.2*	*3.8*	*2.3*	*1.5*
Total Tons	**12.1**	**7.0**	**5.9**	**5.8**
Reduction (%) from 2005	N/A	42%	51%	52%
Emissions with Existing Program plus Revised 2010 Commitments				
Additional Emission Reductions with Commitments	N/A	N/A	-2.2	-4.0
Tons Remaining	**12.1**	**7.0**	**3.7**	**1.8**
Reduction (%) from 2005	N/A	42%	69%	85%
Additional Reduction (%) Attributable to the Commitments in Future Years	N/A	N/A	**37%**	**69%**

Table A-16
UP Commerce Railyard
Updated Estimated Maximum Individual Cancer Risk

	Excess Maximum Individual Cancer Risk for 70-Year Exposure (chances in a million)			
	2005	**2010**	**2015**	**2020**
Existing Program	500	290	245	240
Existing Program + Commitments	N/A	290	155	75
Total Reduction (%) from 2005 Due to Existing Program+ Commitments	N/A	42%	69%	85%

Table A-17
UP Commerce Railyard
Updated Estimated Population Exposure to Excess Cancer Risk Greater than 10 in a Million

	Number of People Exposed			
	2005	**2010**	**2015**	**2020**
Existing Program	270,000	178,000	140,000	136,000
Existing Program + Commitments	N/A	178,000	67,000	22,000
Total Reduction (%) from 2005 Due to Existing Program+ Commitments	N/A	34%	75%	92%

4. UP ICTF/Dolores

Table A-18
UP ICTF/Dolores Railyards
Updated Estimated Diesel PM Emissions by Equipment Type
(tons per year)

Equipment Type	2005	2010	2015	2020
Emissions with Existing Program Only				
Freight Locomotives				
- Line Haul	1.2	0.6	0.8	1.0
- Switch	5.6	0.6	0.7	1.0
- Service/Testing	1.2	0.6	0.8	0.9
Subtotal for Locomotives	*8.0*	*1.8*	*2.3*	*2.9*
Cargo Equipment	4.4	1.6	1.0	0.5
Drayage Trucks	5.9	0.8	0.8	0.7
Transport Refrigeration Units	1.5	0.5	0.5	0.3
Diesel Heavy Equipment	0.4	0.2	0.1	0.1
Maintenance/Stationary	0.06	0.04	0.1	0.1
Subtotal for Other Equipment	*12.3*	*3.1*	*2.5*	*1.7*
Total Tons	**20.3**	**4.9**	**4.8**	**4.6**
Reduction (%) from 2005	N/A	76%	76%	77%
Emissions with Existing Program plus Revised 2010 Commitments				
Additional Emission Reductions with Commitments	N/A	N/A	0	-1.6
Tons Remaining	**20.3**	**4.9**	**4.8**	**3.0**
Reduction (%) from 2005	N/A	76%	76%	85%
Additional Reduction (%) Attributable to the Commitments in Future Years	N/A	N/A	**0%**	**35%**

Table A-19
UP ICTF/Dolores Railyards
Updated Estimated Maximum Individual Cancer Risk

	Excess Maximum Individual Cancer Risk for 70-Year Exposure (chances in a million)			
	2005	**2010**	**2015**	**2020**
Existing Program	800	190	180	180
Existing Program + Commitments	N/A	190	180	120
Total Reduction (%) from 2005 Due to Existing Program + Commitments	N/A	76%	76%	85%

Table A-20
UP ICTF/Dolores Railyards
Updated Estimated Population Exposure to Excess Cancer Risk Greater than 10 in a Million

	Number of People Exposed			
	2005	**2010**	**2015**	**2020**
Existing Program	600,000	156,000	143,000	123,000
Existing Program + Commitments	N/A	156,000	143,000	65,500
Total Reduction (%) from 2005 Due to Existing Program + Commitments	N/A	76%	76%	89%

APPENDIX B

REVISED 2010 COMMITMENTS
FOR THE BNSF SAN BERNARDINO RAILYARD

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Revised 2010 Commitments for BNSF San Bernardino Railyard

The Air Resources Board (ARB) requests additional commitments from BNSF Railway (BNSF) to further reduce diesel particulate matter (PM) emissions at the BNSF San Bernardino Railyard between 2010 and 2020 (hereinafter referred to as the Revised 2010 Commitments).

If BNSF fails to 1) achieve the Table B-1 diesel PM emission reduction levels in 2011, 2013, 2015, 2017, or 2020; or 2) provide comprehensive or interim diesel PM emission inventories, air dispersion modeling, or emission reduction plans in compliance with the schedule in Table B-2; ARB will initiate rulemakings as specified in Section 9. The commitments, and ARB oversight, will ensure that the BNSF San Bernardino Railyard diesel PM emission reduction levels are achieved, verifiable, and enforceable.

Summary of Commitments for the BNSF San Bernardino Railyard

BNSF commits to do the following at this railyard:

- Reduce 2005 diesel PM emissions from railyard operations by at least 45 percent by 2011, increasing the reductions to at least 85 percent by 2020, with intermediate commitments for emission reductions in calendar years 2013, 2015, and 2017 to ensure steady progress. BNSF is implementing existing U.S. Environmental Protection Agency (U.S. EPA) and ARB regulations and agreements and commits to initiate any additional actions needed to meet the diesel PM emission reduction levels on the stated schedule. This commitment shall be met irrespective of any increase in activity or growth at the BNSF San Bernardino Railyard through 2020, consistent with the provisions of Section 13.

- As of 2005, BNSF had 14 older switch and medium horsepower locomotives assigned to the BNSF San Bernardino Railyard. Between acceptance of this commitment and December 31, 2015, BNSF plans to complete the replacement or repower of existing older switch and medium horsepower locomotives such that all switch and medium horsepower locomotives that operate within the railyard (more than 25 percent of annual hours or 25 percent of annual miles traveled or 25 percent of annual diesel fuel consumption) meet emission levels of 3.0 g/bhp-hr oxides of nitrogen (NOx) or less and emissions of 0.1 g/bhp-hr PM or less (over the U.S. EPA line-haul duty cycle).

- By December 31, 2012 and December 31, 2013, evaluate and provide recommendations, if any, for implementation of those changes in railyard operations that BNSF believes may significantly reduce railyard diesel PM emissions, or changes in the location of the railyard emission sources that ARB believes may reduce health risk, and that meet all other specified criteria articulated in Section 6.

- Beginning one month after BNSF's acceptance of these commitments, identify any non-preempted switch or medium horsepower locomotive that operates more than five consecutive calendar days within the railyard and subsequently report this information to ARB with BNSF's annual reports pursuant to the 1998 Locomotive NOx Fleet Average Agreement.

- Prepare and submit railyard diesel PM emission inventories, air dispersion modeling analyses, and emission reduction plans in each year specified in Table B-2.

- Work collaboratively with ARB to provide ongoing communication of railyard diesel PM emission reduction progress to the public through local community meetings and fact sheets.

As part of a broader initiative, BNSF commits to:

- Between 2011 and December 31, 2015, work collaboratively with ARB to develop and implement a formal demonstration program for advanced locomotive engines or aftertreatment devices, or other mutually agreed upon technologies to reduce emissions within the railyard. The objective of the locomotive demonstration program will be to support separate, but potentially parallel, efforts to achieve ARB verification of one or more advanced locomotive engines or aftertreatment devices for ultra-low emitting switch and medium horsepower locomotives to achieve emission levels that are equal to or less than U.S. EPA Tier 4 NOx and/or PM emission standards.

- Make available two existing gen-set switch, medium horsepower, or other locomotives annually through 2015 and provide any necessary technical assistance as BNSF's in-kind contribution to support the demonstration program. If the demonstration program is completed prior to 2015, BNSF's obligation to make these locomotives available would be satisfied as of the completion date.

ARB commits to:

- Install and operate one particulate matter (PM2.5) ambient air quality monitor to provide an indication of air quality in the communities near the BNSF San Bernardino Railyard, or to secure a commitment from the South Coast Air Quality Management District to do so, consistent with a siting and operation protocol supported by ARB.

- Prepare periodic health risk assessments (HRAs) as indicated in Table B-3 for the railyard using the comprehensive railyard diesel PM emission inventories and air dispersion modeling analyses submitted by BNSF. Also to prepare periodic estimates of future health risks, through 2020, following BNSF's submittal of draft and final emission reduction plans.

- Review the emission inventories, air dispersion modeling, and emission reduction plans submitted by BNSF to determine the sufficiency of the information provided and notify BNSF of any deficiencies.

- Determine compliance with the diesel PM emission reduction levels for each of the years specified in Table B-1, based on the comprehensive inventories submitted by BNSF and independent ARB verification through inspections, field surveys, and other mechanisms.

- Monitor BNSF's compliance with the commitments in this document, determine if BNSF has met its obligations, and if BNSF has failed to meet the commitments in specified sections, submit rulemakings for locomotives and railyards to the Board within four months from the date of any final determination of non-compliance, as specified in Section 9.

- Support BNSF's efforts to evaluate options for operational changes with technical assistance to evaluate the potential impacts of such changes on health risk for the railyard.

1. What are the commitments to reduce diesel PM emissions?

BNSF shall meet the diesel PM emission reduction levels at the BNSF San Bernardino Railyard by the specified compliance deadlines as set forth in Table B-1 irrespective of receipt of public incentive funds. BNSF may, however, use incentive funds, if available, to achieve the emission reduction levels. This includes funds under Proposition 1B to replace, repower, or retrofit locomotives. To meet the 85 percent reduction level, ARB staff estimates that the railyard diesel PM emissions of 22.2 tons per year in 2005 will need to be reduced to about 3.4 tons per year by 2020.

Typical emission sources within the railyard affected by the diesel PM emission reduction levels in Table B-1 include interstate line haul locomotives, switch and medium horsepower locomotives, drayage trucks, cargo handling equipment such as cranes and yard hostlers, transport refrigeration units operated with drayage trucks or railcars, and stationary engines and maintenance equipment. Passenger locomotive emissions are excluded from the calculation of railyard diesel PM emissions and reductions used to determine compliance with Table B-1.

Table B-1. BNSF San Bernardino Railyard
Diesel PM Emission Reduction Levels and Schedule

Compliance Deadline	Percent Diesel PM Reductions from 2005 Baseline*	Tons per Year Diesel PM Reductions from 2005 Baseline**
December 31, 2011	45 percent	10.0
December 31, 2013	50 percent	11.1
December 31, 2015	68 percent	15.1
December 31, 2017	73 percent	16.2
December 31, 2020	85 percent	18.8

* If, after the effective date of this program, ARB reduces the stringency or extends the effective date of ARB regulations affecting non-locomotive diesel PM emission sources at railyards, or U.S. EPA reduces the stringency or extends the effective date of its locomotive PM emission standards, the diesel PM emission reduction levels will be adjusted by ARB accordingly.
** Tons subject to revision if ARB updates the 2005 Baseline number.

ARB staff will use the emissions inventory reported in the 2005 Health Risk Assessment as the 2005 baseline, together with the comprehensive emission inventory submittals for subsequent years, to determine compliance with the Table B-1 emission reduction levels. If ARB revises the *ARB Railyard Emission Inventory Methodology* (2006), ARB staff will recalculate the 2005 Baseline and apply the percent diesel PM reduction listed in Table B-1 to update the associated tons per year of diesel PM reductions required by each compliance deadline. ARB staff will validate the inventory information through a thorough technical review of the data, ongoing ARB railyard inspections, ARB field surveys, and ARB tracking of locomotive and railyard operations.

2. Does growth change the commitments to reduce diesel PM emissions?

No. BNSF commits to reducing diesel PM emissions from the BNSF San Bernardino Railyard by at least 85 percent by 2020 and meeting the intermediate levels in Table B-1, regardless of the potential increases in railyard activity levels, such as the number of container lifts.

3. How can BNSF reduce railyard diesel PM emissions 85 percent by 2020?

ARB's supporting analysis for feasible emission reductions at the BNSF San Bernardino Railyard is located in a separate document entitled, *Basis for Proposed Commitments to Reduce Diesel Particulate Matter at the BNSF San Bernardino Railyard (Basis for Proposed Commitments:* June 2010*)*. This *Basis for Proposed Commitments* document describes possible options that could be implemented to achieve the Table B-1 diesel PM emission reduction levels.

In 2005, the railyard generated an estimated 22.2 tons per year of diesel PM emissions from freight operations. ARB staff estimates that existing U.S. EPA and ARB regulations and agreements will reduce diesel PM emissions at the railyard down to 7.3 tons per year by 2020 (a 67 percent reduction). ARB staff estimates that BNSF can further cut the railyard diesel PM emissions by 3.9 tons per year by 2020 (achieving an 85 percent reduction compared to 2005 levels).

4. What are the railroad commitments to prepare and submit emission inventories, air dispersion modeling, and emission reduction plans? What are the ARB commitments to publicly release the railroad documents and health risk assessments?

Table B-2 shows the schedule for BNSF to submit the railyard diesel PM emission inventories, air dispersion modeling, and draft and final emission reduction plans. Table B-3 identifies the dates by which ARB shall release the railyard diesel PM emission inventories, air dispersion modeling, health risk assessments, and the emission reduction plans for public review.

Table B-2. BNSF San Bernardino Railyard
Schedule for BNSF Submittal of Documents: Emission Inventories, Air Dispersion Modeling, and Emission Reduction Plans

Calendar Year	Emission Inventory [a]	Air Dispersion Modeling	Draft Emission Reduction Plan	Final Emission Reduction Plan
2010	Dec 31, 2011 (I)	-------	-------	-------
2011	Apr 1, 2012 (C)	Jun 1, 2012	Sep 1, 2012	Dec 31, 2012
2012	Apr 1, 2013 (I)	-------	-------	-------
2013	Apr 1, 2014 (C)	Jun 1, 2014	Sep 1, 2014	Dec 31, 2014
2014	Apr 1, 2015 (I)	-------	-------	-------
2015	Apr 1, 2016 (C)	Jun 1, 2016	Sep 1, 2016	Dec 31, 2016
2016	Apr 1, 2017 (I)	-------	-------	-------
2017	Apr 1, 2018 (C)	Jun 1, 2018	Sep 1, 2018	Dec 31, 2018
2018	Apr 1, 2019 (I)	-------	-------	-------
2019	Apr 1, 2020 (I)	-------	-------	-------
2020	Apr 1, 2021 (C)	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.

Table B-3. BNSF San Bernardino Railyard
Schedule for ARB Release of Documents: Emission Inventories, Air Dispersion Modeling, ARB Health Risk Assessments, and Emission Reduction Plans

Calendar Year	Railroad Emission Inventory [a]	Railroad Air Dispersion Modeling	ARB Health Risk Assessment	Railroad Draft Emission Reduction Plan[b]	Railroad Final Emission Reduction Plan[b]
2010	Jan 15, 2012 (I)	-------	-------	-------	-------
2011	Apr 15, 2012 (C)	Jun 15, 2012	Oct 1, 2012	Oct 1, 2012	Jan 15, 2013
2012	Apr 15, 2013 (I)	-------	-------	-------	-------
2013	Apr 15, 2014 (C)	Jun 15, 2014	Oct 1, 2014	Oct 1, 2014	Jan 15, 2015
2014	Apr 15, 2015 (I)	-------	-------	-------	-------
2015	Apr 15, 2016 (C)	Jun 15, 2016	Oct 1, 2016	Oct 1, 2016	Jan 15, 2017
2016	Apr 15, 2017 (I)	-------	-------	-------	-------
2017	Apr 15, 2018 (C)	Jun 15, 2018	Oct 1, 2018	Oct 1, 2018	Jan 15, 2019
2018	Apr 15, 2019 (I)	-------	-------	-------	-------
2019	Apr 15, 2020 (I)	-------	-------	-------	-------
2020	Apr 15, 2021 (C)	-------	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.
[b] Following submittal of the draft and final emission reduction plans, ARB staff will provide a brief supplemental document that estimates the associated health risk for future compliance years.

a. Railyard Diesel PM Emission Inventories

i. Comprehensive Diesel PM Emission Inventories

BNSF commits to prepare the comprehensive diesel PM emission inventories for calendar years 2011, 2013, 2015, 2017, and 2020. BNSF shall prepare each comprehensive diesel PM emission inventory for the railyard in accordance with *ARB Railyard Emission Inventory Methodology* (2006) or its subsequent revisions, using data for the whole of that calendar year. The comprehensive diesel PM emission inventories will include, to the extent reasonably available, detailed activity information such as locomotive event recorder data, hours of operation for cargo handling equipment and transport refrigeration units, and drayage truck time in operation within the railyard. The comprehensive inventory will also identify activity and growth projections through 2020, and the basis for those projections.

ii. Interim Diesel PM Emission Inventories

BNSF commits to prepare interim diesel PM emission inventories for the railyard for calendar years 2010, 2012, 2014, 2016, 2018, and 2019, using data for the whole of the calendar year. The interim emission inventories will identify and utilize updates on locomotive usage, other equipment changes, and activity levels (e.g., number of lifts, drayage truck activities, locomotive shop releases, if applicable) to quantify changes to the last comprehensive diesel PM emission inventory. The interim inventory for calendar year 2010 will quantify changes to the comprehensive 2005 diesel PM emission inventory. ARB staff will use the interim emission inventories to consider if there are any potential issues with BNSF continuing to make sufficient progress in order to meet the railyard diesel PM emission levels specified in Table B-1.

b. Air Dispersion Modeling

BNSF commits to prepare air dispersion modeling based on the schedule in Table B-2. Air dispersion modeling is to be performed in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. BNSF also commits to provide source apportionment data for receptors defined in the air dispersion model and a source contribution analysis. BNSF also commits to analyze the impacts on the modeled air concentrations from significant updates to the modeling methodology, such as the current version of AERMOD model from U.S. EPA, the availability of updated meteorological data, or any other modeling parameters or inputs which could substantively affect the modeling estimations.

c. Health Risk Assessments

ARB staff commits to prepare health risk assessments using the comprehensive diesel PM emission inventories and air dispersion modeling results. The risk assessments are to be prepared in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. The updated risk assessments will provide detailed information comparing excess cancer risks and non-cancer health effects with the estimates in the 2005 Health Risk Assessment. ARB staff will compare 2005 railyard emissions and associated health effects with risk assessment results for later years using the same or similar methodology, and also include a separate analysis for any subsequent changes in future year methodologies. ARB staff shall complete the health risk assessment reports for the railyard according to the schedule provided in Table B-3.

Following BNSF's submittal of the draft and final emission reduction plans, ARB also commits to provide a brief supplemental document to the public that estimates the associated health risk for future compliance years. If ARB's health risk estimates for the draft emission reduction plan do not project that health risk will continue to be reduced, ARB shall include that information in its written comments to BNSF on BNSF's draft emission reduction plan.

d. Emission Reduction Plans

BNSF commits to submit draft and final emission reduction plans according to the schedule in Table B-2. The emission reduction plans are to be based on the most recent railyard diesel PM emission inventories. The purpose of the plans is for BNSF to detail the actions it will take to reduce railyard emissions down to the levels shown in Table B-1 for the next compliance deadline, and the range of potential actions it intends to pursue for subsequent compliance deadlines. The emission reductions plans will document existing and projected railyard diesel PM emissions through 2020 (accounting for growth), describe changes in source category activities, identify existing and future actions to cut emissions and provide specific implementation schedules for these actions.

e. ARB Review

i. Diesel PM Emission Inventories and Air Dispersion Modeling

Within 20 calendar days of receipt of a railyard comprehensive or interim diesel PM emission inventory, or air dispersion modeling, ARB shall review the submission for completeness and accuracy and will notify BNSF of its findings. If ARB determines that the submission is not complete and accurate, it will, within the above 20-day time period, notify BNSF in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Upon receipt of a notice of deficiency from ARB, BNSF will within 15 calendar days correct the deficiencies and resubmit the submission to ARB. Within 10 calendar days, ARB will notify BNSF as to whether the submission is complete and accurate. If not, ARB will make a preliminary determination of non-compliance following the procedures set forth in Section 9.c.ii below.

ii. Emission Reduction Plans

Within 30 calendar days of receipt of a draft railyard emission reduction plan, ARB shall review the plan for completeness and accuracy and shall notify BNSF of its findings. If ARB determines that the draft plan is not complete and accurate, or that the draft plan, in the ARB staff's opinion, cannot reasonably achieve the diesel PM reductions required by the next compliance deadline as set forth in Table B-1, ARB shall, within the above 30-day time period, notify BNSF in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Within 30 calendar days of receipt of the final plan, ARB shall notify BNSF as to whether the plan is complete, accurate, and can reasonably achieve the diesel PM emission reductions required by the next compliance deadline as set forth in Table B-1, and make sure such written notification is publicly available. If not, ARB shall make a preliminary determination of non-compliance as set forth in Section 9.c.ii below. Subsequently, if the administrative appeals panel fully or partially affirms the finding of ARB staff, BNSF

will have 30 calendar days to submit to ARB a revised final plan for the next compliance deadline to cure any deficiencies upheld by the panel. If BNSF fails to submit a revised final plan or if ARB staff determines the revised final plan is still deficient, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of Section 9.

f. Commitment to Follow Through on Final Emission Reduction Plans

BNSF shall take the necessary actions identified in the final emission reduction plan in accordance with the plan's implementation schedules to meet the diesel PM emission reduction levels for the next compliance deadline as set forth in Table B-1. If BNSF determines that alternative actions not identified in its most recent plan should be implemented to achieve the emission reduction levels for the next compliance deadline, and the alternative actions materially alter the pathway for achieving the emission reductions in the plan, BNSF will within 15 days of its determination notify ARB of the alternative actions and the reasons for the changes.

5. What is the commitment for public meetings and outreach?

BNSF and ARB commit to hold a public meeting no later than December 15 of 2012, 2014, 2016, and 2018, with members of the surrounding community following the release of the most current ARB health risk assessment and BNSF draft emission reduction plan as specified in the Table B-3 schedule. At the public meeting, BNSF and ARB staff will seek public input on the available documents prior to ARB's final determination on the emission reduction plan.

6. What is the commitment to evaluate options for operational changes?

BNSF commits to evaluate and provide recommendations, if any, for the implementation of those changes in railyard operations that BNSF believes may significantly reduce railyard diesel PM emissions or changes in the location of the railyard emission sources that ARB believes may reduce health risk. BNSF shall evaluate potential changes at the BNSF San Bernardino Railyard according to the following schedule, including:

- By December 31, 2012:
  - Electric infrastructure to support operation of rail mounted gantry cranes and stationary transport refrigeration units.

- By December 31, 2013:
  - Relocation of the truck gate (assessment has been prepared as part of the BNSF San Bernardino Railyard mitigation plan process in 2008).
  - Relocation of diesel-fueled yard tractors.
  - Relocation and reduction in hours of operation of diesel-fueled transport refrigeration units.

BNSF will conduct this one-time operational review considering, among other things, the potential diesel PM emissions reductions that could be achieved, the technical feasibility of such actions, the operational impacts on the railyard's throughput velocity and fluidity, safety, the availability of land and access, the costs and cost-effectiveness of such actions, and any railyard-specific factors at the BNSF San Bernardino Railyard. Each operational option shall be analyzed, and recommendations, if any, for implementation will be completed as soon as possible for this railyard, but in any case not later than December 31, 2013. BNSF shall provide the assessment and any recommendations for implementation of operational changes to ARB, and ARB will make them publicly available.

ARB commits to support these efforts with technical assistance and to evaluate the impacts of each potential operational change on the maximum individual cancer risk for the railyard. ARB will make the results of this evaluation publicly available.

7. Will BNSF be able to access incentive funding to support these commitments?

BNSF, to the extent feasible, will compete for federal, State, local, and private incentive funding to supplement its capital expenditures, and to accelerate further diesel PM and NOx emission reductions at this railyard.

Consistent with State law and Board policies, ARB staff will support efforts by BNSF to seek a mix of federal, State, and local incentive funding to accelerate BNSF's ability to meet the diesel PM emission reduction levels for the railyard.

8. What are the provisions for BNSF and ARB to meet and confer?

BNSF agrees to meet and confer with ARB in 2013 regarding the progress being made by locomotive engine manufacturers to produce Tier 4 interstate line haul locomotives and the potential for interstate testing of prototype locomotives to include California.

BNSF agrees to meet and confer with ARB by 2018 to evaluate and explore opportunities for further diesel PM emission reductions by 2020 and beyond.

9. What are the mechanisms for ARB to enforce these commitments? What would trigger ARB to initiate regulatory action?

a. Potential ARB Actions to Enforce the Revised 2010 Commitments

Upon a final determination of the ARB Executive Officer, or if appealed, of the administrative appeals panel that BNSF has failed to meet its commitments set forth herein at Sections 1, 2, 4, 5, and 6, ARB commits to submit to the Board within four months from the date of the determined failure the following locomotive and railyard rulemakings:

- A regulation of switch and medium horsepower locomotives that are not preempted under federal law (e.g., locomotives that primarily operate in California and that were manufactured prior to 1973 or that exceed 133 percent of their useful life since original manufacture or last remanufacture, whichever is later).

- A designated railyard regulation that requires risk reduction audits and plans to achieve targeted emission reduction levels.

ARB will also consider the following actions:

- Pursue federal legislation to expand ARB authority to adopt regulations for in-use locomotives.

- Petition U.S. EPA to strengthen existing federal locomotive regulations.

ARB is designated as the agency responsible for enforcement of the BNSF commitments. The enforcement authorities specified herein may only be exercised by ARB. BNSF may, at any time, initiate informal consultations with ARB to identify and resolve concerns or other issues regarding compliance with its commitments herein.

In determining whether BNSF has met its commitments, ARB and BNSF (for purposes of this section, individually referred to as "a party" and collectively referred to as "the parties") agree to the following exclusive process.

b. ARB Verification of Railyard Diesel PM Emission Reduction Levels

To determine whether BNSF has met the BNSF San Bernardino Railyard diesel PM emission reduction levels specified in Table B-1, ARB will review the comprehensive emission inventories and interim emission inventories in relation to information collected by ARB staff. ARB will conduct semi-annual railyard inspections, which will also be augmented by ARB photographic tracking and field surveys of railyard switch and medium horsepower locomotives. In addition, ARB staff will use the annual BNSF locomotive NOx fleet average agreement submittals to verify the number and tier of interstate line haul locomotives operating within the South Coast Air Basin. ARB staff will also randomly conduct inspections of BNSF interstate line haul locomotives entering and exiting the South Coast Air Basin to help assess compliance with the Table B-1 diesel PM emission reduction levels.

c. Preliminary Determination of Non-Compliance

i. Failure to Comply with the Railyard Diesel PM Emission Reduction Levels

Within 30 working days of receipt of the comprehensive railyard diesel PM emission inventories, ARB shall make a written preliminary determination notifying BNSF as to whether BNSF met or failed to meet the diesel PM emission reduction levels specified in

Table B-1 for the previous year. If ARB determines that BNSF has failed to meet its emission reduction levels, ARB shall within the same 30 working days provide BNSF with its written preliminary determination, which will set forth the reasons for its findings. ARB will, with the greatest precision possible based on data submitted by BNSF, calculate the difference between the railyard diesel PM emission reduction level reported by BNSF and the levels required in Table B-1. ARB and BNSF shall use their respective best efforts to expedite submission and review of the reports. The time periods provided for ARB to make a preliminary compliance determination may be extended by written agreement between ARB and BNSF.

Within 15 calendar days of receipt of ARB's preliminary determination that BNSF has failed to meet the emission reduction levels, BNSF may request to meet and confer with ARB and/or provide ARB with such information and analysis as BNSF believes appropriate to demonstrate its compliance with the Table B-1 diesel PM emission reduction levels. If a meet and confer is requested, the parties shall meet within 10 working days of the request. Within 15 calendar days after receipt of BNSF's response or after meeting and conferring with ARB, ARB shall review and consider the information provided by BNSF and make a final determination, in writing, as to whether BNSF has failed to meet the Table B-1 diesel PM emission reduction levels. ARB will make such final written determination publicly available.

For the Table B-1 compliance deadlines in 2011, 2013, 2015, 2017, or 2020, if ARB staff determines that BNSF missed its percentage target for the BNSF San Bernardino Railyard by not more than 2 percent (e.g., reaching a 53 percent compliance level where 55 percent was required), BNSF will be given the opportunity to cure this deficiency by the next calendar year, provided it demonstrates the new compliance level by conducting a full inventory analysis. Failure to conduct the analysis or failure to cure the deficiency in the following calendar year shall constitute a failure to meet the appropriate targets in Table B-1.

ii. Failure to Comply with Other Railyard Commitments

If ARB makes a preliminary determination that BNSF has failed to meet any other of its commitments set forth herein, ARB shall notify BNSF, in writing, of its findings. Within 15 calendar days, BNSF may request to meet and confer with ARB and/or provide ARB with such information and analysis as BNSF believes appropriate to demonstrate its compliance. If a meet and confer is requested, the parties shall meet within 10 working days of the request.

Within 15 calendar days after receipt of BNSF's response or after meeting and conferring with ARB, ARB will review and consider the information provided by BNSF and make a final determination, in writing, as to whether BNSF has failed to meet any of its non-emission reduction-related commitments. ARB will make such final written determination publicly available.

d. Final Determination by ARB of Non-Compliance

A final determination of non-compliance shall specifically identify the reasons why ARB has found BNSF not to be in compliance with agreed-upon commitments. A final determination of non-compliance for failure to meet the emission reduction levels set forth in Table B-1 will provide ARB's final calculations of the emission reduction levels of the BNSF San Bernardino Railyard. Findings of BNSF's failure to meet other commitments shall set forth in detail ARB's determination of why the commitments have not been met. ARB will publicly post its final determination notice of non-compliance on its website and make available such notice on a list serve that will be established for notifying the public about compliance with the railyard emission reduction commitments.

e. Dispute Resolution

In the event of a dispute concerning an ARB final determination of non-compliance or any dispute arising between ARB and BNSF concerning their respective commitments, the party asserting the dispute shall provide notice to the other party and set forth the issues underlying the dispute. The parties shall meet and confer regarding the identified issues within 15 working days after receipt of notification, and if they cannot reach agreement within 15 working days after such consultation, shall submit their respective positions to an administrative appeals panel, which shall consider the matter as expeditiously as possible. Except for confidential trade secret information, ARB will publicly post on its website and make available by the aforementioned list serve all documents submitted by the parties to the administrative hearing panel. ARB will also post and make available a notice that interested persons may submit written statements of position and supporting documentation to the administrative appeals panel that will be made part of the record of the hearing.

i. Composition of Administrative Appeals Panel

The panel shall be comprised of one member selected by ARB, one member selected by BNSF, and a third member selected by the initial two members from a list of five or more persons that the parties shall agree to within 120 calendar days of their exchange of commitment letters. The list shall include persons qualified to hear matters that are likely to be heard by the dispute resolution panel. From the list of five or more persons, the parties shall select the person most readily available to hear the matter within 30 calendar days (or as soon thereafter as possible) from the date that the person is contacted by either the ARB or BNSF panel member. If no person from the previously selected list is available to hear the matter within 45 calendar days of being notified, the ARB and BNSF panel members shall contact an arbitration referral service, identify the matter(s) at issue and accept from the service a list of five persons who are qualified to hear the matter(s) at issue and are readily available. The two panel members selected by the parties may mutually agree on one of the five persons to serve on the panel, but if they cannot agree, each panel member will alternatively strike one person from the list until just one person remains. The two panel members selected by the parties will serve as technical advisors to the third panel member, who shall serve as the presiding

member of the panel and who shall be solely responsible for making the final decision on behalf of the panel.

ii. Administrative Appeals Panel Process

Unless otherwise determined that the matter(s) at issue require oral testimony, the panel shall make its decision based upon the written submissions of ARB and BNSF and any written statements submitted by interested persons (see below). If a hearing to take testimony is determined to be necessary, the hearing shall be public. The panel shall determine the time and place of the hearing, and will set forth the procedures to be followed at the hearing. The panel will take all precautions necessary to preserve the confidentiality of trade secret or other confidential information, and will consider such evidence in a closed meeting.

iii. Public Comments to Administrative Appeals Panel

Interested persons may submit written statements and supporting documentation to the panel regarding the matter(s) at issue before the matter(s) are taken under submission, however, only ARB and BNSF shall be parties to the dispute resolution process.

iv. Final Decision by Administrative Appeals Panel

The panel presiding member shall issue his or her final decision on behalf of the panel within 30 calendar days from the date that the matter is submitted to the panel. While either party receiving an adverse decision from the panel may seek expedited review of the decision in the Superior Court for the County of Sacramento, if the panel's decision upholds the Executive Officer's final determination of non-compliance, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of this section. If judicial review is not sought, then the decision of the panel will be binding on ARB and BNSF, as well as any interested person or Intended Beneficiary of the Revised 2010 Commitments (see below).

v. Costs and Fees

Each party to the proceedings outlined above will bear its own costs and fees, with the exception that the parties agree to split all costs and fees arising from the employment of the third panel member.

10. What are the rights of residents near railyards to enforce ARB's Revised 2010 Commitments?

a. Rights of Persons Other Than ARB and BNSF

Residents living within two miles of the BNSF San Bernardino Railyard are the intended beneficiaries (Intended Beneficiaries) of these Revised 2010 Commitments and are entitled to bring an action in mandamus in the Superior Court of Sacramento against ARB to ensure that ARB meets its commitments under the Revised 2010 Commitments.

The Intended Beneficiaries will be bound by the outcomes of all dispute resolution processes engaged in by ARB and BNSF. If BNSF fails to meet its commitments under the Revised 2010 Commitments, only ARB has the right to exercise the provisions of Section 9, which are the exclusive remedies provided under the Revised 2010 Commitments for non-compliance by BNSF. Except as provided in Section 10, the Revised 2010 Commitments do not create any new rights, including the right of enforcement, for any person (including Intended Beneficiaries) or entity other than ARB or BNSF.

b. Notice and Opportunity to Cure

To provide ARB with an opportunity to cure or otherwise address an alleged failure by ARB to meet one of its commitments under the Revised 2010 Commitments, Intended Beneficiaries shall provide ARB with at least 45 days written notice of its intent to seek an order of mandamus from the Superior Court of Sacramento. The notice shall identify the alleged failure, the harm caused by the alleged failure, and the factual basis supporting the allegation. If ARB receives such a notice, ARB shall forward a complete copy to BNSF and Union Pacific Railroad (UP) within five working days and shall within a reasonable period of time thereafter notify BNSF, UP, and the Intended Beneficiaries who provided ARB with notice of the pending action as to whether ARB has been able to cure (or is in the process of curing) the alleged failure or whether the alleged failure is incurable in ARB's view.

If ARB fails to cure or to take reasonable steps towards promptly curing the alleged failure within 45 days after receiving notice, the Intended Beneficiaries may proceed to file above-referenced mandamus action in the Superior Court of Sacramento.

11. How will BNSF handle the disposition of any pre-Tier 0 locomotive formerly based in the BNSF San Bernardino Railyard?

BNSF shall not reassign any pre-Tier 0 locomotive formerly based in the BNSF San Bernardino Railyard to another railyard in California.

12. What are the requirements if BNSF is considering withdrawal from these Revised 2010 Commitments?

The parties are pledged to successful implementation of the Revised 2010 Commitments. BNSF will meet and confer with ARB prior to any action to withdraw from these Revised 2010 Commitments. BNSF and ARB may mutually elect to amend the Revised 2010 Commitments to withdraw or modify specific provisions. If a reasonable resolution cannot be achieved, BNSF may withdraw from the Revised 2010 Commitments as specifically provided below.

a. ARB Action Prior to Meeting the Requirements of Section 9

If ARB proceeds with the rulemakings or other actions identified in Section 9.a. prior to a final determination of BNSF non-compliance with the Revised 2010 Commitments, BNSF may withdraw from these Commitments.

b. Other Reasons

If either of the following actions occurs, BNSF may also withdraw from the Revised 2010 Commitments, but BNSF shall continue to comply with Section 13 to maintain progress through December 31, 2020:

- ARB invokes its remedies under Section 9.a. according to the process prescribed in Section 9.

- An agency of the federal government, the State of California (other than ARB), or a local subdivision of the State of California enacts, mandates, or requires BNSF to perform an action at the BNSF San Bernardino Railyard or affecting this railyard that is identical or substantially similar to actions required to meet these Revised 2010 Commitments. However, actions taken by the City of Los Angeles Harbor Department, the City of Long Beach (acting by and through its Board of Harbor Commissioners), or the Intermodal Container Transfer Facility – Joint Powers Authority related to implementation of the San Pedro Bay Ports Clean Air Action Plan or approval of a new railyard or expansion of an existing railyard do not constitute grounds for BNSF to withdraw from these Revised 2010 Commitments.

13. How will BNSF maintain the progress already made at the BNSF San Bernardino Railyard if BNSF withdraws from these Revised 2010 Commitments?

BNSF agrees to do all of the following in the event that BNSF withdraws from these Revised 2010 Commitments at the BNSF San Bernardino Railyard for any reason other than that specified in Section 12.a.:

- Through December 31, 2020, substantially maintain the emission reductions required by Table B-1 that were achieved by implementation of these Revised 2010 Commitments at the BNSF San Bernardino Railyard through the last compliance deadline. From the date that Section 13 is triggered, subsequent growth in railroad operations is excluded from this provision.

- Through December 31, 2020, provide a report to ARB for the BNSF San Bernardino Railyard that demonstrates maintenance of progress as described above. BNSF shall provide this report every other year, beginning two years following the date of withdrawal.

14. What are the general meet and confer provisions?

In order to assure successful implementation of these Revised 2010 Commitments, BNSF and ARB may at any time meet and confer to review accomplishments, to assess any implementation issues, or to determine if any changes are necessary to improve the overall effectiveness of the Revised 2010 Commitments.

15. What are the rights of ARB and BNSF notwithstanding these Revised 2010 Commitments?

Nothing in this agreement precludes ARB from developing regulations within its authority as required to achieve the goals of the State Implementation Plan and Climate Change Scoping Plan.

BNSF is implementing its commitments notwithstanding the preemptive effect of the federal Interstate Commerce Commission Termination Act ("ICCTA"), the Clean Air Act, the Commerce Clause and other federal law. BNSF and ARB recognize that railroads are to a significant degree regulated by federal law, and that aspects of State and local authority to regulate railroads, rail operations, and locomotives are preempted. By executing and performing the Revised 2010 Commitments, BNSF and ARB agree that there is no waiver or modification of any aspect of federal preemption or setting of any precedent as to preemption, reservation of rights or voluntary compliance with other commitments, rules or agreements.

If ARB proceeds with the rulemaking or other actions identified in Section 9.a., BNSF reserves all legal and procedural rights to contest said rulemakings or actions.

16. What constitutes the full understanding of the Parties?

This document constitutes the full understanding and agreement of ARB and BNSF with respect to the BNSF San Bernardino Railyard regarding the subject matter of the Revised 2010 Commitments. ARB and BNSF have voluntarily entered into the Revised 2010 Commitments, and nothing in the Revised 2010 Commitments affects the scope of ARB's regulatory authority or the scope of preemption under federal law. ARB and BNSF agree that no amendment to the Revised 2010 Commitments shall be binding unless in writing and signed by authorized representatives of ARB and BNSF.

These Revised 2010 Commitments do not revoke, reduce, amend, or modify the undertakings of BNSF in any previous agreements which remain in effect on the date of this document.

17. What are the effective dates of these Revised 2010 Commitments?

These Revised 2010 Commitments shall take effect upon execution by both parties and remain in effect until December 31, 2020 unless amended by ARB and BNSF.

IN WITNESS WHEREOF, the parties have executed these Revised 2010 Commitments.

CALIFORNIA AIR RESOURCES BOARD, an agency of the State of California	THE BNSF RAILWAY COMPANY, a Delaware corporation
James N. Goldstene Executive Officer	Greg C. Fox Executive Vice President, Operations
Date	Date
Address for notice: 1001 "I" Street P.O. Box 2815 Sacramento, CA 95812	Address for notice: 2650 Lou Menk Drive, Second Floor Fort Worth, TX 76131-2830

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APPENDIX C

REVISED 2010 COMMITMENTS FOR THE BNSF HOBART RAILYARD

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Revised 2010 Commitments for BNSF Hobart Railyard

The Air Resources Board (ARB) requests additional commitments from BNSF Railway (BNSF) to further reduce diesel particulate matter (PM) emissions at the BNSF Hobart Railyard between 2010 and 2020 (hereinafter referred to as the Revised 2010 Commitments).

If BNSF fails to 1) achieve the Table C-1 diesel PM emission reduction levels in 2011, 2013, 2015, 2017, or 2020; or 2) provide comprehensive or interim diesel PM emission inventories, air dispersion modeling, or emission reduction plans in compliance with the schedule in Table C-2; ARB will initiate rulemakings as specified in Section 9. The commitments, and ARB oversight, will ensure that the BNSF Hobart Railyard diesel PM emission reduction levels are achieved, verifiable, and enforceable.

Summary of Commitments for the BNSF Hobart Railyard

BNSF commits to do the following at this railyard:

- Reduce 2005 diesel PM emissions from railyard operations by at least 55 percent by 2011, increasing the reductions to at least 85 percent by 2020, with intermediate commitments for emission reductions in calendar years 2013, 2015, and 2017 to ensure steady progress. BNSF is implementing existing U.S. Environmental Protection Agency (U.S. EPA) and ARB regulations and agreements and commits to initiate any additional actions needed to meet the diesel PM emission reduction levels on the stated schedule. This commitment shall be met irrespective of any increase in activity or growth at the BNSF Hobart Railyard through 2020, consistent with the provisions of Section 13.

- As of 2005, BNSF had 18 older switch and medium horsepower locomotives assigned to the BNSF Hobart Railyard. Between acceptance of this commitment and December 31, 2015, BNSF plans to complete the replacement or repower of existing older switch and medium horsepower locomotives such that all switch and medium horsepower locomotives that operate within the railyard (more than 25 percent of annual hours or 25 percent of annual miles traveled or 25 percent of annual diesel fuel consumption) meet emission levels of 3.0 g/bhp-hr oxides of nitrogen (NOx) or less and emissions of 0.1 g/bhp-hr PM or less (over the U.S. EPA line haul duty cycle).

- By December 31, 2012 and December 31, 2013, evaluate and provide recommendations, if any, for implementation of those changes in railyard operations that BNSF believes may significantly reduce railyard diesel PM emissions or changes in the location of the railyard emission sources that ARB believes may reduce health risk, and that meet all other specified criteria articulated in Section 6.

- Beginning one month after BNSF's acceptance of these commitments, identify any non-preempted switch or medium horsepower locomotive that operates more than five consecutive calendar days within the railyard and subsequently report this information to ARB with BNSF's annual reports pursuant to the 1998 Locomotive NOx Fleet Average Agreement.

- Prepare and submit railyard diesel PM emission inventories, air dispersion modeling analyses, and emission reduction plans in each year specified in Table C-2.

- Work collaboratively with ARB to provide ongoing communication of railyard diesel PM emission reduction progress to the public through local community meetings and fact sheets.

As part of a broader initiative, BNSF commits to:

- Between 2011 and December 31, 2015, work collaboratively with ARB to develop and implement a formal demonstration program for advanced locomotive engines or aftertreatment devices, or other mutually agreed upon technologies to reduce emissions within the railyard. The objective of the locomotive demonstration program will be to support separate, but potentially parallel, efforts to achieve ARB verification of one or more advanced locomotive engines or aftertreatment devices for ultra-low emitting switch and medium horsepower locomotives to achieve emission levels that are equal to or less than U.S. EPA Tier 4 NOx and/or PM emission standards.

- Make available two existing gen-set switch, medium horsepower, or other locomotives annually through 2015 and provide any necessary technical assistance as BNSF's in-kind contribution to support the demonstration program. If the demonstration program is completed prior to 2015, BNSF's obligation to make these locomotives available would be satisfied as of the completion date.

ARB commits to:

- Install and operate one particulate matter (PM2.5) ambient air quality monitor to provide an indication of air quality in the communities near the BNSF Hobart and UP Commerce Railyards, or to secure a commitment from the South Coast Air Quality Management District to do so, consistent with a siting and operation protocol supported by ARB.

- Prepare periodic health risk assessments (HRAs) as indicated in Table C-3 for the railyard using the comprehensive railyard diesel PM emission inventories and air dispersion modeling analyses submitted by BNSF. Also to prepare periodic estimates of future health risks, through 2020, following BNSF's submittal of draft and final emission reduction plans.

- Review the emission inventories, air dispersion modeling, and emission reduction plans submitted by BNSF to determine the sufficiency of the information provided and notify BNSF of any deficiencies.

- Determine compliance with the diesel PM emission reduction levels for each of the years specified in Table C-1, based on the comprehensive inventories submitted by BNSF and independent ARB verification through inspections, field surveys, and other mechanisms.

- Monitor BNSF's compliance with the commitments in this document, determine if BNSF has met its obligations, and if BNSF has failed to meet the commitments in specified sections, submit rulemakings for locomotives and railyards to the Board within four months from the date of any final determination of non-compliance, as specified in Section 9.

- Support BNSF's efforts to evaluate options for operational changes with technical assistance to evaluate the potential impacts of such changes on health risk for the railyard.

1. What are the commitments to reduce diesel PM emissions?

BNSF shall meet the diesel PM emission reduction levels at the BNSF Hobart Railyard by the specified compliance deadlines as set forth in Table C-1 irrespective of receipt of public incentive funds. BNSF may, however, use incentive funds, if available, to achieve the emission reduction levels. This includes funds under Proposition 1B to replace, repower, or retrofit locomotives. To meet the 85 percent reduction level, ARB staff estimates that the railyard diesel PM emissions of 24.2 tons per year in 2005 will need to be reduced to about 3.6 tons per year by 2020.

Typical emission sources within the railyard affected by the diesel PM emission reduction levels in Table C-1 include interstate line haul locomotives, switch and medium horsepower locomotives, drayage trucks, cargo handling equipment such as cranes and yard hostlers, transport refrigeration units operated with drayage trucks or railcars, and stationary engines and maintenance equipment. Passenger locomotive emissions are excluded from the calculation of railyard diesel PM emissions and reductions used to determine compliance with Table C-1.

Table C-1. BNSF Hobart Railyard
Diesel PM Emission Reduction Levels and Schedule

Compliance Deadline	Percent Diesel PM Reductions from 2005 Baseline*	Tons per Year Diesel PM Reductions from 2005 Baseline**
December 31, 2011	55 percent	13.3
December 31, 2013	65 percent	15.7
December 31, 2015	76 percent	18.4
December 31, 2017	78 percent	18.9
December 31, 2020	85 percent	20.6

* If, after the effective date of this program, ARB reduces the stringency or extends the effective date of ARB regulations affecting non-locomotive diesel PM emission sources at railyards, or U.S. EPA reduces the stringency or extends the effective date of its locomotive PM emission standards, the diesel PM emission reduction levels will be adjusted by ARB accordingly.
** Tons subject to revision if ARB updates the 2005 Baseline number.

ARB staff will use the emissions inventory reported in the 2005 Health Risk Assessment as the 2005 baseline, together with the comprehensive emission inventory submittals for subsequent years, to determine compliance with the Table C-1 emission reduction levels. If ARB revises the *ARB Railyard Emission Inventory Methodology* (2006), ARB staff will recalculate the 2005 Baseline and apply the percent diesel PM reduction listed in Table C-1 to update the associated tons per year of diesel PM reductions required by each compliance deadline. ARB staff will validate the inventory information through a thorough technical review of the data, ongoing ARB railyard inspections, ARB field surveys, and ARB tracking of locomotive and railyard operations.

ARB has acknowledged that BNSF recently shifted all operations at BNSF Commerce Eastern Railyard, which was closed 2008, to the BNSF Hobart Railyard, which resulted in a diesel PM emission increase at the Hobart Railyard. BNSF agrees to absorb all incremental diesel PM emission increases resulting from the Commerce Eastern Railyard operational shift.

2. Does growth change the commitments to reduce diesel PM emissions?

No. BNSF commits to reducing diesel PM emissions from the BNSF Hobart Railyard by at least 85 percent by 2020 and meeting the intermediate levels in Table C-1, regardless of the potential increases in railyard activity levels, such as the number of container lifts.

3. How can BNSF reduce railyard diesel PM emissions 85 percent by 2020?

ARB's supporting analysis for feasible emission reductions at the BNSF Hobart Railyard is located in a separate document entitled, *Basis for Proposed Commitments to Reduce*

Diesel Particulate Matter at the BNSF Hobart Railyard (Basis for Proposed Commitments: June 2010*)*. This *Basis for Proposed Commitments* document describes possible options that could be implemented to achieve the Table C-1 diesel PM emission reduction levels.

In 2005, the railyard generated an estimated 24.2 tons per year of diesel PM emissions from freight operations. ARB staff estimates that existing U.S. EPA and ARB regulations and agreements will reduce diesel PM emissions at the railyard down to 6.6 tons per year by 2020 (a 73 percent reduction). ARB staff estimates that BNSF can further cut the railyard diesel PM emissions by 3.0 tons per year by 2020 (achieving an 85 percent reduction compared to 2005 levels).

4. What are the railroad commitments to prepare and submit emission inventories, air dispersion modeling, and emission reduction plans? What are the ARB commitments to publicly release the railroad documents and health risk assessments?

Table C-2 shows the schedule for BNSF to submit the railyard diesel PM emission inventories, air dispersion modeling, and draft and final emission reduction plans. Table C-3 identifies the dates by which ARB shall release the railyard diesel PM emission inventories, air dispersion modeling, health risk assessments, and the emission reduction plans for public review.

Table C-2. BNSF Hobart Railyard
Schedule for BNSF Submittal of Documents: Emission Inventories, Air Dispersion Modeling, and Emission Reduction Plans

Calendar Year	Emission Inventory[a]	Air Dispersion Modeling	Draft Emission Reduction Plan	Final Emission Reduction Plan
2010	Dec 31, 2011 (I)	-------	-------	-------
2011	Apr 1, 2012 (C)	Jun 1, 2012	Sep 1, 2012	Dec 31, 2012
2012	Apr 1, 2013 (I)	-------	-------	-------
2013	Apr 1, 2014 (C)	Jun 1, 2014	Sep 1, 2014	Dec 31, 2014
2014	Apr 1, 2015 (I)	-------	-------	-------
2015	Apr 1, 2016 (C)	Jun 1, 2016	Sep 1, 2016	Dec 31, 2016
2016	Apr 1, 2017 (I)	-------	-------	-------
2017	Apr 1, 2018 (C)	Jun 1, 2018	Sep 1, 2018	Dec 31, 2018
2018	Apr 1, 2019 (I)	-------	-------	-------
2019	Apr 1, 2020 (I)	-------	-------	-------
2020	Apr 1, 2021 (C)	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.

Table C-3. BNSF Hobart Railyard
Schedule for ARB Release of Documents: Emission Inventories, Air Dispersion Modeling, ARB Health Risk Assessments, and Emission Reduction Plans

Calendar Year	Railroad Emission Inventory[a]	Railroad Air Dispersion Modeling	ARB Health Risk Assessment	Railroad Draft Emission Reduction Plan[b]	Railroad Final Emission Reduction Plan[b]
2010	Jan 15, 2012 (I)	-------	-------	-------	-------
2011	Apr 15, 2012 (C)	Jun 15, 2012	Oct 1, 2012	Oct 1, 2012	Jan 15, 2013
2012	Apr 15, 2013 (I)	-------	-------	-------	-------
2013	Apr 15, 2014 (C)	Jun 15, 2014	Oct 1, 2014	Oct 1, 2014	Jan 15, 2015
2014	Apr 15, 2015 (I)	-------	-------	-------	-------
2015	Apr 15, 2016 (C)	Jun 15, 2016	Oct 1, 2016	Oct 1, 2016	Jan 15, 2017
2016	Apr 15, 2017 (I)	-------	-------	-------	-------
2017	Apr 15, 2018 (C)	Jun 15, 2018	Oct 1, 2018	Oct 1, 2018	Jan 15, 2019
2018	Apr 15, 2019 (I)	-------	-------	-------	-------
2019	Apr 15, 2020 (I)	-------	-------	-------	-------
2020	Apr 15, 2021 (C)	-------	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.
[b] Following submittal of the draft and final emission reduction plans, ARB staff will provide a brief supplemental document that estimates the associated health risk for future compliance years.

a. Railyard Diesel PM Emission Inventories

i. Comprehensive Diesel PM Emission Inventories

BNSF commits to prepare the comprehensive diesel PM emission inventories for calendar years 2011, 2013, 2015, 2017, and 2020. BNSF shall prepare each comprehensive diesel PM emission inventory for the railyard in accordance with *ARB Railyard Emission Inventory Methodology* (2006) or its subsequent revisions, using data for the whole of that calendar year. The comprehensive diesel PM emission inventories will include, to the extent reasonably available, detailed activity information such as locomotive event recorder data, hours of operation for cargo handling equipment and transport refrigeration units, and drayage truck time in operation within the railyard. The comprehensive inventory will also identify activity and growth projections through 2020, and the basis for those projections.

ii. Interim Diesel PM Emission Inventories

BNSF commits to prepare interim diesel PM emission inventories for the railyard for calendar years 2010, 2012, 2014, 2016, 2018, and 2019, using data for the whole of the calendar year. The interim emission inventories will identify and utilize updates on locomotive usage, other equipment changes, and activity levels (e.g., number of lifts, drayage truck activities, locomotive shop releases, if applicable) to quantify changes to the last comprehensive diesel PM emission inventory. The interim inventory for calendar year 2010 will quantify changes to the comprehensive 2005 diesel PM emission inventory. ARB staff will use the interim emission inventories to consider if there are any potential issues with BNSF continuing to make sufficient progress in order to meet the railyard diesel PM emission levels specified in Table C-1.

b. Air Dispersion Modeling

BNSF commits to prepare air dispersion modeling based on the schedule in Table C-2. Air dispersion modeling is to be performed in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. BNSF also commits to provide source apportionment data for receptors defined in the air dispersion model and a source contribution analysis. BNSF also commits to analyze the impacts on the modeled air concentrations from significant updates to the modeling methodology, such as the current version of AERMOD model from U.S. EPA, the availability of updated meteorological data, or any other modeling parameters or inputs which could substantively affect the modeling estimations.

c. Health Risk Assessments

ARB staff commits to prepare health risk assessments using the comprehensive diesel PM emission inventories and air dispersion modeling results. The risk assessments are to be prepared in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. The updated risk assessments will provide detailed information comparing excess cancer risks and non-cancer health effects with the estimates in the 2005 Health Risk Assessment. ARB staff will compare 2005 railyard emissions and associated health effects with risk assessment results for later years using the same or similar methodology, and also include a separate analysis for any subsequent changes in future year methodologies. ARB staff shall complete the health risk assessment reports for the railyard according to the schedule provided in Table C-3.

Following BNSF's submittal of the draft and final emission reduction plans, ARB also commits to provide a brief supplemental document to the public that estimates the associated health risk for future compliance years. If ARB's health risk estimates for the draft emission reduction plan do not project that health risk will continue to be reduced, ARB shall include that information in its written comments to BNSF on BNSF's draft emission reduction plan.

d. Emission Reduction Plans

BNSF commits to submit draft and final emission reduction plans according to the schedule in Table C-2. The emission reduction plans are to be based on the most recent railyard diesel PM emission inventories. The purpose of the plans is for BNSF to detail the actions it will take to reduce railyard emissions down to the levels shown in Table C-1 for the next compliance deadline, and the range of potential actions it intends to pursue for subsequent compliance deadlines. The emission reductions plans will document existing and projected railyard diesel PM emissions through 2020 (accounting for growth), describe changes in source category activities, identify existing and future actions to cut emissions and provide specific implementation schedules for these actions.

e. ARB Review

i. Diesel PM Emission Inventories and Air Dispersion Modeling

Within 20 calendar days of receipt of a railyard comprehensive or interim diesel PM emission inventory, or air dispersion modeling, ARB shall review the submission for completeness and accuracy and will notify BNSF of its findings. If ARB determines that the submission is not complete and accurate, it will, within the above 20-day time period, notify BNSF in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Upon receipt of a notice of deficiency from ARB, BNSF will within 15 calendar days correct the deficiencies and resubmit the submission to ARB. Within 10 calendar days, ARB will notify BNSF as to whether the submission is complete and accurate. If not, ARB will make a preliminary determination of non-compliance following the procedures set forth in Section 9.c.ii below.

ii. Emission Reduction Plans

Within 30 calendar days of receipt of a draft railyard emission reduction plan, ARB shall review the plan for completeness and accuracy and shall notify BNSF of its findings. If ARB determines that the draft plan is not complete and accurate, or that the draft plan, in the ARB staff's opinion, cannot reasonably achieve the diesel PM reductions required by the next compliance deadline as set forth in Table C-1, ARB shall, within the above 30-day time period, notify BNSF in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Within 30 calendar days of receipt of the final plan, ARB shall notify BNSF as to whether the plan is complete, accurate, and can reasonably achieve the diesel PM emission reductions required by the next compliance deadline as set forth in Table C-1, and make sure such written notification is publicly available. If not, ARB shall make a preliminary determination of non-compliance as set forth in Section 9.c.ii below. Subsequently, if the administrative appeals panel fully or partially affirms the finding of

ARB staff, BNSF will have 30 calendar days to submit to ARB a revised final plan for the next compliance deadline to cure any deficiencies upheld by the panel. If BNSF fails to submit a revised final plan or if ARB staff determines the revised final plan is still deficient, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of Section 9.

f. Commitment to Follow Through on Final Emission Reduction Plan

BNSF shall take the necessary actions identified in the final emission reduction plan in accordance with the plan's implementation schedules to meet the diesel PM emission reduction levels for the next compliance deadline as set forth in Table C-1. If BNSF determines that alternative actions not identified in its most recent plan should be implemented to achieve the emission reduction levels for the next compliance deadline, and the alternative actions materially alter the pathway for achieving the emission reductions in the plan, BNSF will within 15 days of its determination notify ARB of the alternative actions and the reasons for the changes.

5. What is the commitment for public meetings and outreach?

BNSF and ARB commit to hold a public meeting no later than December 15 of 2012, 2014, 2016, and 2018, with members of the surrounding community following the release of the most current ARB health risk assessment and BNSF draft emission reduction plan as specified in the Table C-3 schedule. At the public meeting, BNSF and ARB staff will seek public input on the available documents prior to ARB's final determination on the emission reduction plan.

6. What is the commitment to evaluate options for operational changes?

BNSF commits to evaluate and provide recommendations, if any, for the implementation of those changes in railyard operations that BNSF believes may significantly reduce railyard diesel PM emissions or changes in the location of the railyard emission sources that ARB believes may reduce health risk. BNSF shall evaluate potential changes at the BNSF Hobart Railyard according to the following schedule, including:

- By December 31, 2012:
  - Relocation of the truck gate; and/or automated gate system, and/or installation of a bridge to provide access for trucks to the railyard.
  - Electric infrastructure to support operation of rail mounted gantry cranes and stationary transport refrigeration units.

- By December 31, 2013:
  - Relocation of diesel-fueled yard tractors and transport refrigeration units.

BNSF will conduct this one-time operational review considering, among other things, the potential diesel PM emissions reductions that could be achieved, the technical feasibility of such actions, the operational impacts on the railyard's throughput velocity and fluidity, safety, the availability of land and access, the costs and cost-effectiveness of such actions, and any railyard-specific factors at the BNSF Hobart Railyard. Each operational option shall be analyzed, and recommendations, if any, for implementation will be completed as soon as possible for this railyard, but in any case not later than December 31, 2013. BNSF shall provide the assessment and any recommendations for implementation of operational changes to ARB, and ARB will make them publicly available.

ARB commits to support these efforts with technical assistance and to evaluate the impacts of each potential operational change on the maximum individual cancer risk for the railyard. ARB will make the results of this evaluation publicly available.

7. Will BNSF be able to access incentive funding to support these commitments?

BNSF, to the extent feasible, will compete for federal, State, local, and private incentive funding to supplement its capital expenditures, and to accelerate further diesel PM and NOx emission reductions at this railyard.

Consistent with State law and Board policies, ARB staff will support efforts by BNSF to seek a mix of federal, State, and local incentive funding to accelerate BNSF's ability to meet the diesel PM emission reduction levels for the railyard.

8. What are the provisions for BNSF and ARB to meet and confer?

BNSF agrees to meet and confer with ARB in 2013 regarding the progress being made by locomotive engine manufacturers to produce Tier 4 interstate line haul locomotives and the potential for interstate testing of prototype locomotives to include California.

BNSF agrees to meet and confer with ARB by 2018 to evaluate and explore opportunities for further diesel PM emission reductions by 2020 and beyond.

9. What are the mechanisms for ARB to enforce these commitments? What would trigger ARB to initiate regulatory action?

a. Potential ARB Actions to Enforce the Revised 2010 Commitments

Upon a final determination of the ARB Executive Officer, or if appealed, of the administrative appeals panel that BNSF has failed to meet its commitments set forth herein at Sections 1, 2, 4, 5, and 6, ARB commits to submit to the Board within four months from the date of the determined failure the following locomotive and railyard rulemakings:

- A regulation of switch and medium horsepower locomotives that are not preempted under federal law (e.g., locomotives that primarily operate in California and that were manufactured prior to 1973 or that exceed 133 percent of their useful life since original manufacture or last remanufacture, whichever is later).

- A designated railyard regulation that requires risk reduction audits and plans to achieve targeted emission reduction levels.

ARB will also consider the following actions:

- Pursue federal legislation to expand ARB authority to adopt regulations for in-use locomotives.

- Petition U.S. EPA to strengthen existing federal locomotive regulations.

ARB is designated as the agency responsible for enforcement of the BNSF commitments. The enforcement authorities specified herein may only be exercised by ARB. BNSF may, at any time, initiate informal consultations with ARB to identify and resolve concerns or other issues regarding compliance with its commitments herein.

In determining whether BNSF has met its commitments, ARB and BNSF (for purposes of this section, individually referred to as "a party" and collectively referred to as "the parties") agree to the following exclusive process.

b. ARB Verification of Railyard Diesel PM Emission Reduction Levels

To determine whether BNSF has met the BNSF Hobart Railyard diesel PM emission reduction levels specified in Table C-1, ARB will review the comprehensive emission inventories and interim emission inventories in relation to information collected by ARB staff. ARB will conduct semi-annual railyard inspections, which will also be augmented by ARB photographic tracking and field surveys of railyard switch and medium horsepower locomotives. In addition, ARB staff will use the annual BNSF locomotive NOx fleet average agreement submittals to verify the number and tier of interstate line haul locomotives operating within the South Coast Air Basin. ARB staff will also randomly conduct inspections of BNSF interstate line haul locomotives entering and exiting the South Coast Air Basin to help assess compliance with the Table C-1 diesel PM emission reduction levels.

c. Preliminary Determination of Non-Compliance

i. Failure to Comply with the Railyard Diesel PM Emission Reduction Levels

Within 30 working days of receipt of the comprehensive railyard diesel PM emission inventories, ARB shall make a written preliminary determination notifying BNSF as to whether BNSF met or failed to meet the diesel PM emission reduction levels specified in

Table C-1 for the previous year. If ARB determines that BNSF has failed to meet its emission reduction levels, ARB shall within the same 30 working days provide BNSF with its written preliminary determination, which will set forth the reasons for its findings. ARB will, with the greatest precision possible based on data submitted by BNSF, calculate the difference between the railyard diesel PM emission reduction level reported by BNSF and the levels required in Table C-1. ARB and BNSF shall use their respective best efforts to expedite submission and review of the reports. The time periods provided for ARB to make a preliminary compliance determination may be extended by written agreement between ARB and BNSF.

Within 15 calendar days of receipt of ARB's preliminary determination that BNSF has failed to meet the emission reduction levels, BNSF may request to meet and confer with ARB and/or provide ARB with such information and analysis as BNSF believes appropriate to demonstrate its compliance with the Table C-1 diesel PM emission reduction levels. If a meet and confer is requested, the parties shall meet within 10 working days of the request. Within 15 calendar days after receipt of BNSF's response or after meeting and conferring with ARB, ARB shall review and consider the information provided by BNSF and make a final determination, in writing, as to whether BNSF has failed to meet the Table C-1 diesel PM emission reduction levels. ARB will make such final written determination publicly available.

For the Table C-1 compliance deadlines in 2011, 2013, 2015, 2017, or 2020, if ARB staff determines that BNSF missed its percentage target for the BNSF Hobart Railyard by not more than 2 percent (e.g., reaching a 63 percent compliance level where 65 percent was required), BNSF will be given the opportunity to cure this deficiency by the next calendar year, provided it demonstrates the new compliance level by conducting a full inventory analysis. Failure to conduct the analysis or failure to cure the deficiency in the following calendar year shall constitute a failure to meet the appropriate targets in Table C-1.

ii. Failure to Comply with Other Railyard Commitments

If ARB makes a preliminary determination that BNSF has failed to meet any other of its commitments set forth herein, ARB shall notify BNSF, in writing, of its findings. Within 15 calendar days, BNSF may request to meet and confer with ARB and/or provide ARB with such information and analysis as BNSF believes appropriate to demonstrate its compliance. If a meet and confer is requested, the parties shall meet within 10 working days of the request.

Within 15 calendar days after receipt of BNSF's response or after meeting and conferring with ARB, ARB will review and consider the information provided by BNSF and make a final determination, in writing, as to whether BNSF has failed to meet any of its non-emission reduction-related commitments. ARB will make such final written determination publicly available.

d. Final Determination by ARB of Non-Compliance

A final determination of non-compliance shall specifically identify the reasons why ARB has found BNSF not to be in compliance with agreed-upon commitments. A final determination of non-compliance for failure to meet the emission reduction levels set forth in Table C-1 will provide ARB's final calculations of the emission reduction levels of the BNSF Hobart Railyard. Findings of BNSF's failure to meet other commitments shall set forth in detail ARB's determination of why the commitments have not been met. ARB will publicly post its final determination notice of non-compliance on its website and make available such notice on a list serve that will be established for notifying the public about compliance with the railyard emission reduction commitments.

e. Dispute Resolution

In the event of a dispute concerning an ARB final determination of non-compliance or any dispute arising between ARB and BNSF concerning their respective commitments, the party asserting the dispute shall provide notice to the other party and set forth the issues underlying the dispute. The parties shall meet and confer regarding the identified issues within 15 working days after receipt of notification, and if they cannot reach agreement within 15 working days after such consultation, shall submit their respective positions to an administrative appeals panel, which shall consider the matter as expeditiously as possible. Except for confidential trade secret information, ARB will publicly post on its website and make available by the aforementioned list serve all documents submitted by the parties to the administrative hearing panel. ARB will also post and make available a notice that interested persons may submit written statements of position and supporting documentation to the administrative appeals panel that will be made part of the record of the hearing.

i. Composition of Administrative Appeals Panel

The panel shall be comprised of one member selected by ARB, one member selected by BNSF, and a third member selected by the initial two members from a list of five or more persons that the parties shall agree to within 120 calendar days of their exchange of commitment letters. The list shall include persons qualified to hear matters that are likely to be heard by the dispute resolution panel. From the list of five or more persons, the parties shall select the person most readily available to hear the matter within 30 calendar days (or as soon thereafter as possible) from the date that the person is contacted by either the ARB or BNSF panel member. If no person from the previously selected list is available to hear the matter within 45 calendar days of being notified, the ARB and BNSF panel members shall contact an arbitration referral service, identify the matter(s) at issue and accept from the service a list of five persons who are qualified to hear the matter(s) at issue and are readily available. The two panel members selected by the parties may mutually agree on one of the five persons to serve on the panel, but if they cannot agree, each panel member will alternatively strike one person from the list until just one person remains. The two panel members selected by the parties will serve as technical advisors to the third panel member, who shall serve as the presiding

member of the panel and who shall be solely responsible for making the final decision on behalf of the panel.

ii. Administrative Appeals Panel Process

Unless otherwise determined that the matter(s) at issue require oral testimony, the panel shall make its decision based upon the written submissions of ARB and BNSF and any written statements submitted by interested persons (see below). If a hearing to take testimony is determined to be necessary, the hearing shall be public. The panel shall determine the time and place of the hearing, and will set forth the procedures to be followed at the hearing. The panel will take all precautions necessary to preserve the confidentiality of trade secret or other confidential information, and will consider such evidence in a closed meeting.

iii. Public Comments to Administrative Appeals Panel

Interested persons may submit written statements and supporting documentation to the panel regarding the matter(s) at issue before the matter(s) are taken under submission, however, only ARB and BNSF shall be parties to the dispute resolution process.

iv. Final Decision by Administrative Appeals Panel

The panel presiding member shall issue his or her final decision on behalf of the panel within 30 calendar days from the date that the matter is submitted to the panel. While either party receiving an adverse decision from the panel may seek expedited review of the decision in the Superior Court for the County of Sacramento, if the panel's decision upholds the Executive Officer's final determination of non-compliance, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of this section. If judicial review is not sought, then the decision of the panel will be binding on ARB and BNSF, as well as any interested person or Intended Beneficiary of the Revised 2010 Commitments (see below).

v. Costs and Fees

Each party to the proceedings outlined above will bear its own costs and fees, with the exception that the parties agree to split all costs and fees arising from the employment of the third panel member.

10. What are the rights of residents near railyards to enforce ARB's Revised 2010 Commitments?

a. Rights of Persons Other Than ARB and BNSF

Residents living within two miles of the BNSF Hobart Railyard are the intended beneficiaries (Intended Beneficiaries) of these Revised 2010 Commitments and are entitled to bring an action in mandamus in the Superior Court of Sacramento against ARB to ensure that ARB meets its commitments under the Revised 2010 Commitments.

The Intended Beneficiaries will be bound by the outcomes of all dispute resolution processes engaged in by ARB and BNSF. If BNSF fails to meet its commitments under the Revised 2010 Commitments, only ARB has the right to exercise the provisions of Section 9, which are the exclusive remedies provided under the Revised 2010 Commitments for non-compliance by BNSF. Except as provided in Section 10, the Revised 2010 Commitments do not create any new rights, including the right of enforcement, for any person (including Intended Beneficiaries) or entity other than ARB or BNSF.

b. Notice and Opportunity to Cure

To provide ARB with an opportunity to cure or otherwise address an alleged failure by ARB to meet one of its commitments under the Revised 2010 Commitments, Intended Beneficiaries shall provide ARB with at least 45 days written notice of its intent to seek an order of mandamus from the Superior Court of Sacramento. The notice shall identify the alleged failure, the harm caused by the alleged failure, and the factual basis supporting the allegation. If ARB receives such a notice, ARB shall forward a complete copy to BNSF and Union Pacific Railroad (UP) within five working days and shall within a reasonable period of time thereafter notify BNSF, UP, and the Intended Beneficiaries who provided ARB with notice of the pending action as to whether ARB has been able to cure (or is in the process of curing) the alleged failure or whether the alleged failure is incurable in ARB's view.

If ARB fails to cure or to take reasonable steps towards promptly curing the alleged failure within 45 days after receiving notice, the Intended Beneficiaries may proceed to file above-referenced mandamus action in the Superior Court of Sacramento.

11. How will BNSF handle the disposition of any pre-Tier 0 locomotive formerly based in the BNSF Hobart Railyard?

BNSF shall not reassign any pre-Tier 0 locomotive formerly based in the BNSF Hobart Railyard to another railyard in California.

12. What are the requirements if BNSF is considering withdrawal from these Revised 2010 Commitments?

The parties are pledged to successful implementation of the Revised 2010 Commitments. BNSF will meet and confer with ARB prior to any action to withdraw from these Revised 2010 Commitments. BNSF and ARB may mutually elect to amend the Revised 2010 Commitments to withdraw or modify specific provisions. If a reasonable resolution cannot be achieved, BNSF may withdraw from the Revised 2010 Commitments as specifically provided below.

a. ARB Action Prior to Meeting the Requirements of Section 9

If ARB proceeds with the rulemakings or other actions identified in Section 9.a. prior to a final determination of BNSF non-compliance with the Revised 2010 Commitments, BNSF may withdraw from these Commitments.

b. Other Reasons

If either of the following actions occurs, BNSF may also withdraw from the Revised 2010 Commitments, but BNSF shall continue to comply with Section 13 to maintain progress through December 31, 2020:

- ARB invokes its remedies under Section 9.a. according to the process prescribed in Section 9.

- An agency of the federal government, the State of California (other than ARB), or a local subdivision of the State of California enacts, mandates, or requires BNSF to perform an action at the BNSF Hobart Railyard or affecting this railyard that is identical or substantially similar to actions required to meet these Revised 2010 Commitments. However, actions taken by the City of Los Angeles Harbor Department, the City of Long Beach (acting by and through its Board of Harbor Commissioners), or the Intermodal Container Transfer Facility – Joint Powers Authority related to implementation of the San Pedro Bay Ports Clean Air Action Plan or approval of a new railyard or expansion of an existing railyard do not constitute grounds for BNSF to withdraw from these Revised 2010 Commitments.

13. How will BNSF maintain the progress already made at the BNSF Hobart Railyard if BNSF withdraws from these Revised 2010 Commitments?

BNSF agrees to do all of the following in the event that BNSF withdraws from these Revised 2010 Commitments at the BNSF Hobart Railyard for any reason other than that specified in Section 12.a.:

- Through December 31, 2020, substantially maintain the emission reductions required by Table C-1 that were achieved by implementation of these Revised 2010 Commitments at the BNSF Hobart Railyard through the last compliance deadline. From the date that Section 13 is triggered, subsequent growth in railroad operations is excluded from this provision.

- Through December 31, 2020, provide a report to ARB for the BNSF Hobart Railyard that demonstrates maintenance of progress as described above. BNSF shall provide this report every other year, beginning two years following the date of withdrawal.

14. What are the general meet and confer provisions?

In order to assure successful implementation of these Revised 2010 Commitments, BNSF and ARB may at any time meet and confer to review accomplishments, to assess any implementation issues, or to determine if any changes are necessary to improve the overall effectiveness of the Revised 2010 Commitments.

15. What are the rights of ARB and BNSF notwithstanding these Revised 2010 Commitments?

Nothing in this agreement precludes ARB from developing regulations within its authority as required to achieve the goals of the State Implementation Plan and Climate Change Scoping Plan.

BNSF is implementing its commitments notwithstanding the preemptive effect of the federal Interstate Commerce Commission Termination Act ("ICCTA"), the Clean Air Act, the Commerce Clause and other federal law. BNSF and ARB recognize that railroads are to a significant degree regulated by federal law, and that aspects of State and local authority to regulate railroads, rail operations, and locomotives are preempted. By executing and performing the Revised 2010 Commitments, BNSF and ARB agree that there is no waiver or modification of any aspect of federal preemption or setting of any precedent as to preemption, reservation of rights or voluntary compliance with other commitments, rules or agreements.

If ARB proceeds with the rulemaking or other actions identified in Section 9.a., BNSF reserves all legal and procedural rights to contest said rulemakings or actions.

16. What constitutes the full understanding of the Parties?

This document constitutes the full understanding and agreement of ARB and BNSF with respect to the BNSF Hobart Railyard regarding the subject matter of the Revised 2010 Commitments. ARB and BNSF have voluntarily entered into the Revised 2010 Commitments, and nothing in the Revised 2010 Commitments affects the scope of ARB's regulatory authority or the scope of preemption under federal law. ARB and BNSF agree that no amendment to the Revised 2010 Commitments shall be binding unless in writing and signed by authorized representatives of ARB and BNSF.

These Revised 2010 Commitments do not revoke, reduce, amend, or modify the undertakings of BNSF in any previous agreements which remain in effect on the date of this document.

17. What are the effective dates of these Revised 2010 Commitments?

These Revised 2010 Commitments shall take effect upon execution by both parties and remain in effect until December 31, 2020 unless amended by ARB and BNSF.

IN WITNESS WHEREOF, the parties have executed these Revised 2010 Commitments.

CALIFORNIA AIR RESOURCES BOARD, an agency of the State of California	THE BNSF RAILWAY COMPANY, a Delaware corporation
James N. Goldstene Executive Officer	Greg C. Fox Executive Vice President, Operations
Date	Date
Address for notice: 1001 "I" Street P.O. Box 2815 Sacramento, CA 95812	Address for notice: 2650 Lou Menk Drive, Second Floor Fort Worth, TX 76131-2830

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APPENDIX D

REVISED 2010 COMMITMENTS FOR THE UP COMMERCE RAILYARD

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Revised 2010 Commitments for the UP Commerce Railyard

The Air Resources Board (ARB) requests additional commitments from Union Pacific Railroad (UP) to further reduce diesel particulate matter (PM) emissions at the UP Commerce Railyard between 2010 and 2020 (hereinafter referred to as the Revised 2010 Commitments).

If UP fails to 1) achieve the Table D-1 diesel PM emission reduction levels in 2011, 2013, 2015, 2017, or 2020; or 2) provide comprehensive or interim diesel PM emission inventories, air dispersion modeling, or emission reduction plans in compliance with the schedule in Table D-2; ARB will initiate rulemakings as specified in Section 9. The commitments, and ARB oversight, will ensure that the UP Commerce Railyard diesel PM emission reduction levels are achieved, verifiable, and enforceable.

Summary of Commitments for the UP Commerce Railyard:

UP commits to do the following at this railyard:

- Reduce 2005 diesel PM emissions from railyard operations by at least 50 percent by 2011, increasing the reductions to at least 85 percent by 2020, with intermediate commitments for emission reductions in calendar years 2013, 2015, and 2017 to ensure steady progress. UP is implementing existing U.S. Environmental Protection Agency (U.S. EPA) and ARB regulations and agreements and commits to initiate any additional actions needed to meet the diesel PM emission reduction levels on the stated schedule. This commitment shall be met irrespective of any increase in activity or growth at the UP Commerce Railyard through 2020, consistent with the provisions of Section 13.

- Ensure that any additional switch or medium horsepower locomotives that operate within the railyard (more than 25 percent of annual hours or 25 percent of annual miles traveled or 25 percent of annual diesel fuel consumption) meet emission levels of 3.0 g/bhp-hr oxides of nitrogen (NOx) or less and emissions of 0.1 g/bhp-hr PM or less (over the U.S. EPA line-haul duty cycle). UP has already upgraded existing locomotives that operate within the railyard (more than 25 percent of annual hours or 25 percent of annual miles traveled or 25 percent of annual diesel fuel consumption) to meet these emission levels.

- By December 31, 2012 and December 31, 2013, evaluate and provide recommendations, if any, for implementation of those changes in railyard operations that UP believes may significantly reduce railyard diesel PM emissions, or changes in the location of the railyard emission sources that ARB believes may reduce health risk, and that meet all other specified criteria articulated in Section 6.

- Beginning one month after UP's acceptance of these commitments, identify any non-preempted switch or medium horsepower locomotive that operates more than five consecutive calendar days within the railyard and subsequently report this information to ARB with UP's annual reports pursuant to the 1998 Locomotive NOx Fleet Average Agreement.

- Prepare and submit railyard diesel PM emission inventories, air dispersion modeling analyses, and emission reduction plans in each year specified in Table D-2.

- Work collaboratively with ARB to provide ongoing communication of railyard diesel PM emission reduction progress to the public through local community meetings and fact sheets.

As part of a broader initiative, UP commits to:

- Between 2011 and December 31, 2015, work collaboratively with ARB to develop and implement a formal demonstration program for advanced locomotive engines or aftertreatment devices, or other mutually agreed upon technologies to reduce emissions within the railyard. The objective of the locomotive demonstration program will be to support separate, but potentially parallel, efforts to achieve ARB verification of one or more advanced locomotive engines or aftertreatment devices for ultra-low emitting switch and medium horsepower locomotives to achieve emission levels that are equal to or less than U.S. EPA Tier 4 NOx and/or PM emission standards.

- Make available two existing gen-set switch, medium horsepower, or other locomotives annually through 2015 and provide any necessary technical assistance as UP's in-kind contribution to support the demonstration program. If the demonstration program is completed prior to 2015, UP's obligation to make these locomotives available would be satisfied as of the completion date.

ARB commits to:

- Install and operate one particulate matter (PM2.5) ambient air quality monitor to provide an indication of air quality in the communities near the UP Commerce and BNSF Hobart Railyards, or to secure a commitment from the South Coast Air Quality Management District to do so, consistent with a siting and operation protocol supported by ARB.

- Prepare periodic health risk assessments (HRAs) as indicated in Table D-3 for the railyard using the comprehensive railyard diesel PM emission inventories and air dispersion modeling analyses submitted by UP. Also to prepare periodic estimates of future health risks, through 2020, following UP's submittal of draft and final emission reduction plans.

- Review the emission inventories, air dispersion modeling, and emission reduction plans submitted by UP to determine the sufficiency of the information provided and notify UP of any deficiencies.

- Determine compliance with the diesel PM emission reduction levels for each of the years specified in Table D-1, based on the comprehensive inventories submitted by UP and independent ARB verification through inspections, field surveys, and other mechanisms.

- Monitor UP's compliance with the commitments in this document, determine if UP has met its obligations, and if UP has failed to meet the commitments in specified sections, submit rulemakings for locomotives and railyards to the Board within four months from the date of any final determination of non-compliance, as specified in Section 9.

- Support UP's efforts to evaluate options for operational changes with technical assistance to evaluate the potential impacts of such changes on health risk for the railyard.

1. What are the commitments to reduce diesel PM emissions?

UP shall meet the diesel PM emission reduction levels at the UP Commerce Railyard by the specified compliance deadlines set forth in Table D-1 irrespective of receipt of public incentive funds. UP may, however, use incentive funds, if available, to achieve the emission reduction levels. This includes funds under Proposition 1B to replace, repower, or retrofit locomotives. To meet the 85 percent reduction level, ARB staff estimates that the railyard diesel PM emissions of 12.1 tons per year in 2005 will need to be reduced to about 1.8 tons per year by 2020.

Typical emission sources within the railyard affected by the diesel PM emission reduction levels in Table D-1 include interstate line haul locomotives, switch and medium horsepower locomotives, drayage trucks, cargo handling equipment such as cranes and yard hostlers, transport refrigeration units operated with drayage trucks or railcars, and stationary engines and maintenance equipment. Passenger locomotive emissions are excluded from the calculation of railyard diesel PM emissions and reductions used to determine compliance with Table D-1.

Table D-1. UP Commerce Railyard
Diesel PM Emission Reduction Levels and Schedule

Compliance Deadline	Percent Diesel PM Reductions from 2005 Baseline*	Tons per Year Diesel PM Reductions from 2005 Baseline**
December 31, 2011	50 percent	6.1
December 31, 2013	55 percent	6.7
December 31, 2015	69 percent	8.3
December 31, 2017	70 percent	8.5
December 31, 2020	85 percent	10.3

* If, after the effective date of this program, ARB reduces the stringency or extends the effective date of ARB regulations affecting non-locomotive diesel PM emission sources at railyards, or U.S. EPA reduces the stringency or extends the effective date of its locomotive PM emission standards, the diesel PM emission reduction levels will be adjusted by ARB accordingly.
** Tons subject to revision if ARB updates the 2005 Baseline number.

ARB staff will use the emissions inventory reported in the 2005 Health Risk Assessment as the 2005 baseline, together with the comprehensive emission inventory submittals for subsequent years, to determine compliance with the Table D-1 emission reduction levels. If ARB revises the *ARB Railyard Emission Inventory Methodology* (2006), ARB staff will recalculate the 2005 Baseline and apply the percent diesel PM reduction listed in Table D-1 to update the associated tons per year of diesel PM reductions required by each compliance deadline. ARB staff will validate the inventory information through a thorough technical review of the data, ongoing ARB railyard inspections, ARB field surveys, and ARB tracking of locomotive and railyard operations.

2. Does growth change the commitments to reduce diesel PM emissions?

No. UP commits to reducing diesel PM emissions from the UP Commerce Railyard by at least 85 percent by 2020 and meeting the intermediate levels in Table D-1, regardless of the potential increases in railyard activity levels, such as the number of container lifts.

3. How can UP reduce railyard diesel PM emissions 85 percent by 2020?

ARB's supporting analysis for feasible emission reductions at UP Commerce Railyard is located in a separate document entitled, *Basis for Proposed Commitments to Reduce Diesel Particulate Matter at the UP Commerce Railyard* (*Basis for Proposed Commitments:* June 2010*)*. This *Basis for Proposed Commitments* document describes possible options that could be implemented to achieve the Table D-1 diesel PM emission reduction levels.

In 2005, the railyard generated an estimated 12.1 tons per year of diesel PM emissions from freight operations. ARB staff estimates that existing U.S. EPA and ARB

regulations and agreements will reduce diesel PM emissions at the railyard down to 5.8 tons per year by 2020 (a 52 percent reduction). ARB staff estimates that UP can further cut the railyard diesel PM emissions by 4.0 tons per year by 2020 (achieving an 85 percent reduction compared to 2005 levels).

4. What are the railroad commitments to prepare and submit emission inventories, air dispersion modeling, and emission reduction plans? What are the ARB commitments to publicly release the railroad documents and health risk assessments?

Table D-2 shows the schedule for UP to submit the railyard diesel PM emission inventories, air dispersion modeling, and draft and final emission reduction plans. Table D-3 identifies the dates by which ARB shall release the railyard diesel PM emission inventories, air dispersion modeling, health risk assessments, and the emission reduction plans for public review.

Table D-2.
UP Commerce Railyard
Schedule for UP Submittal of Documents: Emission Inventories, Air Dispersion Modeling, and Emission Reduction Plans

Calendar Year	Emission Inventory [a]	Air Dispersion Modeling	Draft Emission Reduction Plan	Final Emission Reduction Plan
2010	Dec 31, 2011 (I)	-------	-------	-------
2011	Apr 1, 2012 (C)	Jun 1, 2012	Sep 1, 2012	Dec 31, 2012
2012	Apr 1, 2013 (I)	-------	-------	-------
2013	Apr 1, 2014 (C)	Jun 1, 2014	Sep 1, 2014	Dec 31, 2014
2014	Apr 1, 2015 (I)	-------	-------	-------
2015	Apr 1, 2016 (C)	Jun 1, 2016	Sep 1, 2016	Dec 31, 2016
2016	Apr 1, 2017 (I)	-------	-------	-------
2017	Apr 1, 2018 (C)	Jun 1, 2018	Sep 1, 2018	Dec 31, 2018
2018	Apr 1, 2019 (I)	-------	-------	-------
2019	Apr 1, 2020 (I)	-------	-------	-------
2020	Apr 1, 2021 (C)	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.

Table D-3. UP Commerce Railyard
Schedule for ARB Release of Documents: Emission Inventories, Air Dispersion Modeling, ARB Health Risk Assessments and Emission Reduction Plans

Calendar Year	Railroad Emission Inventory [a]	Railroad Air Dispersion Modeling	ARB Health Risk Assessment	Railroad Draft Emission Reduction Plan [b]	Railroad Final Emission Reduction Plan [b]
2010	Jan 15, 2012 (I)	-------	-------	-------	-------
2011	Apr 15, 2012 (C)	Jun 15, 2012	Oct 1, 2012	Oct 1, 2012	Jan 15, 2013
2012	Apr 15, 2013 (I)	-------	-------	-------	-------
2013	Apr 15, 2014 (C)	Jun 15, 2014	Oct 1, 2014	Oct 1, 2014	Jan 15, 2015
2014	Apr 15, 2015 (I)	-------	-------	-------	-------
2015	Apr 15, 2016 (C)	Jun 15, 2016	Oct 1, 2016	Oct 1, 2016	Jan 15, 2017
2016	Apr 15, 2017 (I)	-------	-------	-------	-------
2017	Apr 15, 2018 (C)	Jun 15, 2018	Oct 1, 2018	Oct 1, 2018	Jan 15, 2019
2018	Apr 15, 2019 (I)	-------	-------	-------	-------
2019	Apr 15, 2020 (I)	-------	-------	-------	-------
2020	Apr 15, 2021 (C)	-------	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.
[b] Following submittal of the draft and final emission reduction plans, ARB staff will provide a brief supplemental document that estimates the associated health risk for future compliance years.

a. Railyard Diesel PM Emission Inventories

i. Comprehensive Diesel PM Emission Inventories

UP commits to prepare the comprehensive diesel PM emission inventories for calendar years 2011, 2013, 2015, 2017, and 2020. UP shall prepare each comprehensive diesel PM emission inventory for the railyard in accordance with *ARB Railyard Emission Inventory Methodology* (2006) or its subsequent revisions, using data for the whole of that calendar year. The comprehensive diesel PM emission inventories will include, to the extent reasonably available, detailed activity information such as locomotive event recorder data, hours of operation for cargo handling equipment and transport refrigeration units, and drayage truck time in operation within the railyard. The comprehensive inventory will also identify activity and growth projections through 2020, and the basis for those projections.

ii. Interim Diesel PM Emission Inventories

UP commits to prepare interim diesel PM emission inventories for the railyard for calendar years 2010, 2012, 2014, 2016, 2018, and 2019, using data for the whole of the calendar year. The interim emission inventories will identify and utilize updates on locomotive usage, other equipment changes, and activity levels (e.g., number of lifts, drayage truck activities, locomotive shop releases, if applicable) to quantify changes to the last comprehensive diesel PM emission inventory. The interim inventory for calendar year 2010 will quantify changes to the comprehensive 2005 diesel PM emission inventory. ARB staff will use the interim emission inventories to consider if there are any potential issues with UP continuing to make sufficient progress in order to meet the railyard diesel PM emission levels specified in Table D-1.

b. Air Dispersion Modeling

UP commits to prepare air dispersion modeling based on the schedule in Table D-2. Air dispersion modeling is to be performed in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. UP also commits to provide source apportionment data for receptors defined in the air dispersion model and a source contribution analysis. UP also commits to analyze the impacts on the modeled air concentrations from significant updates to the modeling methodology, such as the current version of AERMOD model from U.S. EPA, the availability of updated meteorological data, or any other modeling parameters or inputs which could substantively affect the modeling estimations.

c. Health Risk Assessments

ARB staff commits to prepare health risk assessments using the comprehensive diesel PM emission inventories and air dispersion modeling results. The risk assessments are to be prepared in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. The updated risk assessments will provide detailed information comparing excess cancer risks and non-cancer health effects with the estimates in the 2005 Health Risk Assessment. ARB staff will compare 2005 railyard emissions and associated health effects with risk assessment results for later years using the same or similar methodology, and also include a separate analysis for any subsequent changes in future year methodologies. ARB staff shall complete the health risk assessment reports for the railyard according to the schedule provided in Table D-3.

Following UP's submittal of the draft and final emission reduction plans, ARB also commits to provide a brief supplemental document to the public that estimates the associated health risk for future compliance years. If ARB's health risk estimates for the draft emission reduction plan do not project that health risk will continue to be reduced, ARB shall include that information in its written comments to UP on UP's draft emission reduction plan.

d. Emission Reduction Plans

UP commits to submit draft and final emission reduction plans according to the schedule in Table D-2. The emission reduction plans are to be based on the most recent railyard diesel PM emission inventories. The purpose of the plans is for UP to detail the actions it will take to reduce railyard emissions down to the levels shown in Table D-1 for the next compliance deadline, and the range of potential actions it intends to pursue for subsequent compliance deadlines. The emission reductions plans will document existing and projected railyard diesel PM emissions through 2020 (accounting for growth), describe changes in source category activities, identify existing and future actions to cut emissions and provide specific implementation schedules for these actions.

e. ARB Review

i. Diesel PM Emission Inventories and Air Dispersion Modeling

Within 20 calendar days of receipt of a railyard comprehensive or interim diesel PM emission inventory, or air dispersion modeling, ARB shall review the submission for completeness and accuracy and will notify UP of its findings. If ARB determines that the submission is not complete and accurate, it will, within the above 20-day time period, notify UP in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Upon receipt of a notice of deficiency from ARB, UP will within 15 calendar days correct the deficiencies and resubmit the submission to ARB. Within 10 calendar days, ARB will notify UP as to whether the submission is complete and accurate. If not, ARB will make a preliminary determination of non-compliance following the procedures set forth in Section 9.c.ii below.

ii. Emission Reduction Plans

Within 30 calendar days of receipt of a draft railyard emission reduction plan, ARB shall review the plan for completeness and accuracy and shall notify UP of its findings. If ARB determines that the draft plan is not complete and accurate, or that the draft plan, in ARB staff's opinion, cannot reasonably achieve the diesel PM reductions required by the next compliance deadline as set forth in Table D-1, ARB shall, within the above 30-day time period, notify UP in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Within 30 calendar days of receipt of the final plan, ARB shall notify UP as to whether the plan is complete, accurate, and can reasonably achieve the diesel PM emission reductions required by the next compliance deadline as set forth in Table D-1, and make sure such written notification is publicly available. If not, ARB shall make a preliminary determination of non-compliance as set forth in Section 9.c.ii below. Subsequently, if the administrative appeals panel fully or partially affirms the finding of

ARB staff, UP will have 30 calendar days to submit to ARB a revised final plan for the next compliance deadline to cure any deficiencies upheld by the panel. If UP fails to submit a revised final plan or if ARB staff determines the revised final plan is still deficient, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of Section 9.

f. Commitment to Follow Through on Final Emission Reduction Plan

UP shall take the necessary actions identified in the final emission reduction plan in accordance with the plan's implementation schedules to meet the diesel PM emission reduction levels for the next compliance deadline as set forth in Table D-1. If UP determines that alternative actions not identified in its most recent plan should be implemented to achieve the emission reduction levels for the next compliance deadline, and the alternative actions materially alter the pathway for achieving the emission reductions in the plan, UP will within 15 days of its determination notify ARB of the alternative actions and the reasons for the changes.

5. What is the commitment for public meetings and outreach?

UP and ARB commit to hold a public meeting no later than December 15 of 2012, 2014, 2016, and 2018, with members of the surrounding community following the release of the most current ARB health risk assessment and UP draft emission reduction plan as specified in the Table D-3 schedule. At the public meeting, UP and ARB staff will seek public input on the available documents prior to ARB's final determination on the emission reduction plan.

6. What is the commitment to evaluate options for operational changes?

UP commits to evaluate and provide recommendations, if any, for the implementation of those changes in railyard operations that UP believes may significantly reduce railyard diesel PM emissions or changes in the location of the railyard emission sources that ARB believes may reduce health risk. UP shall evaluate potential changes at the UP Commerce Railyard according to the following schedule, including:

- By December 31, 2012:
  - Installation of a stationary collection system to reduce locomotive maintenance and service related emissions.
  - Relocation of diesel-fueled yard tractors.

- By December 31, 2013:
  - Relocation of the locomotive maintenance and service facilities, including associated essential idling emissions.
  - Electric infrastructure to support operation of rail mounted gantry cranes.

UP will conduct this one-time operational review considering, among other things, the potential diesel PM emissions reductions that could be achieved, the technical feasibility

of such actions, the operational impacts on the railyard's throughput velocity and fluidity, safety, the availability of land and access, the costs and cost-effectiveness of such actions, and any railyard-specific factors at the UP Commerce Railyard. Each operational option shall be analyzed, and recommendations, if any, for implementation will be completed as soon as possible for this railyard, but in any case not later than December 31, 2013. UP shall provide the assessment and any recommendations for implementation of operational changes to ARB, and ARB will make them publicly available.

ARB commits to support these efforts with technical assistance and to evaluate the impacts of each potential operational change on the maximum individual cancer risk for the railyard. ARB will make the results of this evaluation publicly available.

7. Will UP be able to access incentive funding to support these commitments?

UP, to the extent feasible, will compete for federal, State, local, and private incentive funding to supplement its capital expenditures, and to accelerate further diesel PM and NOx emission reductions at this railyard.

Consistent with State law and Board policies, ARB staff will support efforts by UP to seek a mix of federal, State, and local incentive funding to accelerate UP's ability to meet the diesel PM emission reduction levels for the railyard.

8. What are the provisions for UP and ARB to meet and confer?

UP agrees to meet and confer with ARB in 2013 regarding the progress being made by locomotive engine manufacturers to produce Tier 4 interstate line haul locomotives and the potential for interstate testing of prototype locomotives to include California.

UP agrees to meet and confer with ARB by 2018 to evaluate and explore opportunities for further diesel PM emission reductions by 2020 and beyond.

9. What are the mechanisms for ARB to enforce these commitments? What would trigger ARB to initiate regulatory action?

a. Potential ARB Actions to Enforce the Revised 2010 Commitments

Upon a final determination of the ARB Executive Officer, or if appealed, of the administrative appeals panel that UP has failed to meet its commitments set forth herein at Sections 1, 2, 4, 5, and 6, ARB commits to submit to the Board within four months from the date of the determined failure the following locomotive and railyard rulemakings:

- A regulation of switch and medium horsepower locomotives that are not preempted under federal law (e.g., locomotives that primarily operate in California and that were manufactured prior to 1973 or that exceed 133 percent of their useful life since original manufacture or last remanufacture, whichever is later).

- A designated railyard regulation that requires risk reduction audits and plans to achieve targeted emission reduction levels.

ARB will also consider the following actions:

- Pursue federal legislation to expand ARB authority to adopt regulations for in-use locomotives.

- Petition U.S. EPA to strengthen existing federal locomotive regulations.

ARB is designated as the agency responsible for enforcement of the UP commitments. The enforcement authorities specified herein may only be exercised by ARB. UP may, at any time, initiate informal consultations with ARB to identify and resolve concerns or other issues regarding compliance with its commitments herein.

In determining whether UP has met its commitments, ARB and UP (for purposes of this section, individually referred to as "a party" and collectively referred to as "the parties") agree to the following exclusive process.

b. ARB Verification of Railyard Diesel PM Emission Reduction Levels

To determine whether UP has met the UP Commerce Railyard diesel PM emission reduction levels specified in Table D-1, ARB will review the comprehensive emission inventories and interim emission inventories in relation to information collected by ARB staff. ARB will conduct semi-annual railyard inspections, which will also be augmented by ARB photographic tracking and field surveys of railyard switch and medium horsepower locomotives. In addition, ARB staff will use the annual UP locomotive NOx fleet average agreement submittals to verify the number and tier of interstate line haul locomotives operating within the South Coast Air Basin. ARB staff will also randomly conduct inspections of UP interstate line haul locomotives entering and exiting the South Coast Air Basin to help assess compliance with the Table D-1 diesel PM emission reduction levels.

c. Preliminary Determination of Non-Compliance

i. Failure to Comply with the Railyard Diesel PM Emissions Reduction Levels

Within 30 working days of receipt of the comprehensive railyard diesel PM emission inventories, ARB shall make a written preliminary determination notifying UP as to whether UP met or failed to meet the diesel PM emission reduction levels specified in

Table D-1 for the previous year. If ARB determines that UP has failed to meet its emission reduction levels, ARB shall within the same 30 working days provide UP with its written preliminary determination, which will set forth the reasons for its findings. ARB will, with the greatest precision possible based on data submitted by UP, calculate the difference between the railyard diesel PM emission reduction level reported by UP and the levels required in Table D-1. ARB and UP shall use their respective best efforts to expedite submission and review of the reports. The time periods provided for ARB to make a preliminary compliance determination may be extended by written agreement between ARB and UP.

Within 15 calendar days of receipt of ARB's preliminary determination that UP has failed to meet the emission reduction levels, UP may request to meet and confer with ARB and/or provide ARB with such information and analysis as UP believes appropriate to demonstrate its compliance with the Table D-1 diesel PM emission reduction levels. If a meet and confer is requested, the parties shall meet within 10 working days of the request. Within 15 calendar days after receipt of UP's response or after meeting and conferring with ARB, ARB shall review and consider the information provided by UP and make a final determination, in writing, as to whether UP has failed to meet the Table D-1 diesel PM emission reduction levels. ARB will make such final written determination publicly available.

For the Table D-1 compliance deadlines in 2011, 2013, 2017, or 2020, if ARB staff determines that UP missed its percentage target for the UP Commerce Railyard by not more than 2 percent (e.g., reaching a 53 percent compliance level where 55 percent was required), UP will be given the opportunity to cure this deficiency by the next calendar year, provided it demonstrates the new compliance level by conducting a full inventory analysis. For the Table D-1 compliance deadline in 2015, if ARB staff determines that UP missed its percentage target for the UP Commerce Railyard by not more than 2 percent (e.g., reaching a 67 percent compliance level where 69 percent was required), UP will be given the opportunity to cure this deficiency by the next compliance deadline in 2017, provided it demonstrates the new compliance level by conducting a full inventory analysis. Failure to conduct the analysis or failure to cure the deficiency by the required year shall constitute a failure to meet the appropriate targets in Table D-1.

ii. Failure to Comply with Other Railyard Commitments

If ARB makes a preliminary determination that UP has failed to meet any other of its commitments set forth herein, ARB shall notify UP, in writing, of its findings. Within 15 calendar days, UP may request to meet and confer with ARB and/or provide ARB with such information and analysis as UP believes appropriate to demonstrate its compliance. If a meet and confer is requested, the parties shall meet within 10 working days of the request.

Within 15 calendar days after receipt of UP's response or after meeting and conferring with ARB, ARB will review and consider the information provided by UP and make a

final determination, in writing, as to whether UP has failed to meet any of its non-emission reduction-related commitments. ARB will make such final written determination publicly available.

d. Final Determination by ARB of Non-Compliance

A final determination of non-compliance shall specifically identify the reasons why ARB has found UP not to be in compliance with agreed-upon commitments. A final determination of non-compliance for failure to meet the emission reduction levels set forth in Table D-1 will provide ARB's final calculations of the emission reduction levels of the UP Commerce Railyard. Findings of UP's failure to meet other commitments shall set forth in detail ARB's determination of why the commitments have not been met. ARB will publicly post its final determination notice of non-compliance on its website and make available such notice on a list serve that will be established for notifying the public about compliance with the railyard emission reduction commitments.

e. Dispute Resolution

In the event of a dispute concerning an ARB final determination of non-compliance or any dispute arising between ARB and UP concerning their respective commitments, the party asserting the dispute shall provide notice to the other party and set forth the issues underlying the dispute. The parties shall meet and confer regarding the identified issues within 15 working days after receipt of notification, and if they cannot reach agreement within 15 working days after such consultation, shall submit their respective positions to an administrative appeals panel, which shall consider the matter as expeditiously as possible. Except for confidential trade secret information, ARB will publicly post on its website and make available by the aforementioned list serve all documents submitted by the parties to the administrative hearing panel. ARB will also post and make available a notice that interested persons may submit written statements of position and supporting documentation to the administrative appeals panel that will be made part of the record of the hearing.

i. Composition of Administrative Appeals Panel

The panel shall be comprised of one member selected by ARB, one member selected by UP, and a third member selected by the initial two members from a list of five or more persons that the parties shall agree to within 120 calendar days of their exchange of commitment letters. The list shall include persons qualified to hear matters that are likely to be heard by the dispute resolution panel. From the list of five or more persons, the parties shall select the person most readily available to hear the matter within 30 calendar days (or as soon thereafter as possible) from the date that the person is contacted by either the ARB or UP panel member. If no person from the previously selected list is available to hear the matter within 45 calendar days of being notified, the ARB and UP panel members shall contact an arbitration referral service, identify the matter(s) at issue and accept from the service a list of five persons who are qualified to hear the matter(s) at issue and are readily available. The two panel members selected

by the parties may mutually agree on one of the five persons to serve on the panel, but if they cannot agree, each panel member will alternatively strike one person from the list until just one person remains. The two panel members selected by the parties will serve as technical advisors to the third panel member, who shall serve as the presiding member of the panel and who shall be solely responsible for making the final decision on behalf of the panel.

ii. Administrative Appeals Panel Process

Unless otherwise determined that the matter(s) at issue require oral testimony, the panel shall make its decision based upon the written submissions of ARB and UP and any written statements submitted by interested persons (see below). If a hearing to take testimony is determined to be necessary, the hearing shall be public. The panel shall determine the time and place of the hearing, and will set forth the procedures to be followed at the hearing. The panel will take all precautions necessary to preserve the confidentiality of trade secret or other confidential information, and will consider such evidence in a closed meeting.

iii. Public Comments to Administrative Appeals Panel

Interested persons may submit written statements and supporting documentation to the panel regarding the matter(s) at issue before the matter(s) are taken under submission, however, only ARB and UP shall be parties to the dispute resolution process.

iv. Final Decision by Administrative Appeals Panel

The panel presiding member shall issue his or her final decision on behalf of the panel within 30 calendar days from the date that the matter is submitted to the panel. While either party receiving an adverse decision from the panel may seek expedited review of the decision in the Superior Court for the County of Sacramento, if the panel's decision upholds the Executive Officer's final determination of non-compliance, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of this section. If judicial review is not sought, then the decision of the panel will be binding on ARB and UP, as well as any interested person or Intended Beneficiary of the Revised 2010 Commitments (see below).

v. Costs and Fees

Each party to the proceedings outlined above will bear its own costs and fees, with the exception that the parties agree to split all costs and fees arising from the employment of the third panel member.

10. What are the rights of residents near railyards to enforce ARB's Revised 2010 Commitments?

a. Rights of Persons Other Than ARB and UP

Residents living within two miles of the UP Commerce Railyard are the intended beneficiaries (Intended Beneficiaries) of these Revised 2010 Commitments and are entitled to bring an action in mandamus in the Superior Court of Sacramento against ARB to ensure that ARB meets its commitments under the Revised 2010 Commitments.

The Intended Beneficiaries will be bound by the outcomes of all dispute resolution processes engaged in by ARB and UP. If UP fails to meet its commitments under the Revised 2010 Commitments, only ARB has the right to exercise the provisions of Section 9, which are the exclusive remedies provided under the Revised 2010 Commitments for non-compliance by UP. Except as provided in Section 10, the Revised 2010 Commitments do not create any new rights, including the right of enforcement, for any person (including Intended Beneficiaries) or entity other than ARB or UP.

b. Notice and Opportunity to Cure

To provide ARB with an opportunity to cure or otherwise address an alleged failure by ARB to meet one of its commitments under the Revised 2010 Commitments, Intended Beneficiaries shall provide ARB with at least 45 days written notice of its intent to seek an order of mandamus from the Superior Court of Sacramento. The notice shall identify the alleged failure, the harm caused by the alleged failure, and the factual basis supporting the allegation. If ARB receives such a notice, ARB shall forward a complete copy to BNSF Railway (BNSF) and UP within five working days and shall within a reasonable period of time thereafter notify BNSF, UP, and the Intended Beneficiaries who provided ARB with notice of the pending action as to whether ARB has been able to cure (or is in the process of curing) the alleged failure or whether the alleged failure is incurable in ARB's view.

If ARB fails to cure or to take reasonable steps towards promptly curing the alleged failure within 45 days after receiving notice, the Intended Beneficiaries may proceed to file above-referenced mandamus action in the Superior Court of Sacramento.

11. How will UP handle the disposition of any pre-Tier 0 locomotive formerly based in the UP Commerce Railyard?

UP shall not reassign any pre-Tier 0 locomotive formerly based in the UP Commerce Railyard to another railyard in California.

12. What are the requirements if UP is considering withdrawal from these Revised 2010 Commitments?

The parties are pledged to successful implementation of the Revised 2010 Commitments. UP will meet and confer with ARB prior to any action to withdraw from these Revised 2010 Commitments. UP and ARB may mutually elect to amend the Revised 2010 Commitments to withdraw or modify specific provisions. If a reasonable resolution cannot be achieved, UP may withdraw from the Revised 2010 Commitments as specifically provided below.

a. ARB Action Prior to Meeting the Requirements of Section 9

If ARB proceeds with the rulemakings or other actions identified in Section 9.a. prior to a final determination of UP non-compliance with the Revised 2010 Commitments, UP may withdraw from these Commitments.

b. Other Reasons

If either of the following actions occurs, UP may also withdraw from the Revised 2010 Commitments, but UP shall continue to comply with Section 13 to maintain progress through December 31, 2020:

- ARB invokes its remedies under Section 9.a. according to the process prescribed in Section 9.

- An agency of the federal government, the State of California (other than ARB), or a local subdivision of the State of California enacts, mandates, or requires UP to perform an action at the UP Commerce Railyard or affecting this railyard that is identical or substantially similar to actions required to meet these Revised 2010 Commitments. However, actions taken by the City of Los Angeles Harbor Department, the City of Long Beach (acting by and through its Board of Harbor Commissioners), or the Intermodal Container Transfer Facility – Joint Powers Authority related to implementation of the San Pedro Bay Ports Clean Air Action Plan or approval of a new railyard or expansion of an existing railyard do not constitute grounds for UP to withdraw from these Revised 2010 Commitments.

13. How will UP maintain the progress already made at the UP Commerce Railyard if UP withdraws from these Revised 2010 Commitments?

UP agrees to do all of the following in the event that UP withdraws from these Revised 2010 Commitments at the UP Commerce Railyard for any reason other than that specified in Section 12.a.:

- Through December 31, 2020, substantially maintain the emission reductions required by Table D-1 that were achieved by implementation of these Revised 2010 Commitments at the UP Commerce Railyard through the last compliance deadline. From the date that Section 13 is triggered, subsequent growth in railroad operations is excluded from this provision.

- Through December 31, 2020, provide a report to ARB for the UP Commerce Railyard that demonstrates maintenance of progress as described above. UP shall provide this report every other year, beginning two years following the date of withdrawal.

14. What are the general meet and confer provisions?

In order to assure successful implementation of these Revised 2010 Commitments, UP and ARB may at any time meet and confer to review accomplishments, to assess any implementation issues, or to determine if any changes are necessary to improve the overall effectiveness of the Revised 2010 Commitments.

15. What are the rights of ARB and UP notwithstanding these Revised 2010 Commitments?

Nothing in this agreement precludes ARB from developing regulations within its authority as required to achieve the goals of the State Implementation Plan and Climate Change Scoping Plan.

UP is implementing its commitments notwithstanding the preemptive effect of the federal Interstate Commerce Commission Termination Act ("ICCTA"), the Clean Air Act, the Commerce Clause and other federal law. UP and ARB recognize that railroads are to a significant degree regulated by federal law, and that aspects of State and local authority to regulate railroads, rail operations, and locomotives are preempted. By executing and performing the Revised 2010 Commitments, UP and ARB agree that there is no waiver or modification of any aspect of federal preemption or setting of any precedent as to preemption, reservation of rights or voluntary compliance with other commitments, rules or agreements.

If ARB proceeds with the rulemaking or other actions identified in Section 9.a., UP reserves all legal and procedural rights to contest said rulemakings or actions.

16. What constitutes the full understanding of the Parties?

This document constitutes the full understanding and agreement of ARB and UP with respect to the UP Commerce Railyard regarding the subject matter of the Revised 2010 Commitments. ARB and UP have voluntarily entered into the Revised 2010 Commitments, and nothing in the Revised 2010 Commitments affects the scope of ARB's regulatory authority or the scope of preemption under federal law. ARB and UP agree that no amendment to the Revised 2010 Commitments shall be binding unless in writing and signed by authorized representatives of ARB and UP.

These Revised 2010 Commitments do not revoke, reduce, amend, or modify the undertakings of UP in any previous agreements which remain in effect on the date of this document.

17. What are the effective dates of these Revised 2010 Commitments?

These Revised 2010 Commitments shall take effect upon execution by both parties and remain in effect until December 31, 2020 unless amended by ARB and UP.

IN WITNESS WHEREOF, the parties have executed these Revised 2010 Commitments.

CALIFORNIA AIR RESOURCES BOARD, an agency of the State of California	THE UNION PACIFIC RAILROAD COMPANY, a Delaware corporation
James N. Goldstene Executive Officer	Lance M. Fritz Executive Vice President of Operations
Date	Date
Address for notice: 1001 "I" Street P.O. Box 2815 Sacramento, CA 95812	Address for notice: 1400 Douglas Street Omaha, NE 68179

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APPENDIX E

REVISED 2010 COMMITMENTS FOR THE UP ICTF/DOLORES RAILYARDS

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Revised Commitments for the UP ICTF/Dolores Railyards

The Air Resources Board (ARB) requests additional commitments from Union Pacific Railroad (UP) to further reduce diesel particulate matter (PM) emissions at the UP Intermodal Container Transfer Facility (ICTF) and UP Dolores Railyards between 2010 and 2020 (hereinafter referred to as the Revised 2010 Commitments).

The UP ICTF Railyard is an intermodal railyard which was originally built in 1987. The adjacent UP Dolores Railyard is a classification and locomotive maintenance facility built in 1943. For purposes of this document, the UP ICTF/Dolores Railyards are treated as one combined railyard facility (the "railyard").

If UP fails to 1) achieve the Table E-1 diesel PM emission reduction levels in 2011, 2013, 2015, 2017, or 2020; or 2) provide comprehensive or interim diesel PM emission inventories, air dispersion modeling, or emission reduction plans in compliance with the schedule in Table E-2; ARB will initiate rulemakings as specified in Section 9. The commitments, and ARB oversight, will ensure that the UP ICTF/Dolores Railyards diesel PM emission reduction levels are achieved, verifiable, and enforceable.

Summary of Commitments for the UP ICTF/Dolores Railyards

UP commits to do the following at this railyard:

- Reduce 2005 diesel PM emissions from railyard operations by at least 60 percent by 2011, increasing the reductions to at least 85 percent by 2020, with intermediate commitments for emission reductions in calendar years 2013, 2015, and 2017 to ensure steady progress. UP is implementing existing U.S. Environmental Protection Agency (U.S. EPA) and ARB regulations and agreements and commits to initiate any additional actions needed to meet the diesel PM emission reduction levels on the stated schedule. This commitment shall be met irrespective of any increase in activity or growth at the UP ICTF/Dolores Railyards through 2020, including any increase in capacity resulting from the proposed UP ICTF Modernization Plan, consistent with the provisions of Section 13.

- Ensure that any additional switch or medium horsepower locomotives that operate within the railyard (more than 25 percent of annual hours or 25 percent of annual miles traveled or 25 percent of annual diesel fuel consumption) meet emission levels of 3.0 g/bhp-hr oxides of nitrogen (NOx) or less and emissions of 0.1 g/bhp-hr PM or less (over the U.S. EPA line-haul duty cycle). UP has already upgraded existing locomotives that operate within the railyard (more than 25 percent of annual hours or 25 percent of annual miles traveled or 25 percent of annual diesel fuel consumption) to meet these emission levels.

- By December 31, 2012 and December 31, 2013, evaluate and provide recommendations, if any, for implementation of those changes in railyard operations that UP believes may significantly reduce railyard diesel PM emissions, or changes in the location of the railyard emission sources that ARB believes may reduce health risk, and that meet all other specified criteria articulated in Section 6.

- Beginning one month after UP's acceptance of these commitments, identify any non-preempted switch or medium horsepower locomotive that operates more than five consecutive calendar days within the railyard and subsequently report this information to ARB with UP's annual reports pursuant to the 1998 Locomotive NOx Fleet Average Agreement.

- Prepare and submit railyard diesel PM emission inventories, air dispersion modeling analyses, and emission reduction plans in each year specified in Table E-2.

- Work collaboratively with ARB to provide ongoing communication of railyard diesel PM emission reduction progress to the public through local community meetings and fact sheets.

As part of a broader initiative, UP commits to:

- Between 2011 and December 31, 2015, work collaboratively with ARB to develop and implement a formal demonstration program for advanced locomotive engines or aftertreatment devices, or other mutually agreed upon technologies to reduce emissions within the railyard. The objective of the locomotive demonstration program will be to support separate, but potentially parallel, efforts to achieve ARB verification of one or more advanced locomotive engines or aftertreatment devices for ultra-low emitting switch and medium horsepower locomotives to achieve emission levels that are equal to or less than U.S. EPA Tier 4 NOx and/or PM emission standards.

- Make available two existing gen-set switch, medium horsepower, or other locomotives annually through 2015 and provide any necessary technical assistance as UP's in-kind contribution to support the demonstration program. If the demonstration program is completed prior to 2015, UP's obligation to make these locomotives available would be satisfied as of the completion date.

ARB commits to:

- Prepare periodic health risk assessments (HRAs) as indicated in Table E-3 for the railyard using the comprehensive railyard diesel PM emission inventories and air dispersion modeling analyses submitted by UP. Also to prepare periodic estimates of future health risks, through 2020, following UP's submittal of draft and final emission reduction plans.

- Review the emission inventories, air dispersion modeling, and emission reduction plans submitted by UP to determine the sufficiency of the information provided and notify UP of any deficiencies.

- Determine compliance with the diesel PM emission reduction levels for each of the years specified in Table E-1, based on the comprehensive inventories submitted by UP and independent ARB verification through inspections, field surveys, and other mechanisms.

- Monitor UP's compliance with the commitments in this document, determine if UP has met its obligations, and if UP has failed to meet the commitments in specified sections, submit rulemakings for locomotives and railyards to the Board within four months from the date of any final determination of non-compliance, as specified in Section 9.

- Support UP's efforts to evaluate options for operational changes with technical assistance to evaluate the potential impacts of such changes on health risk for the railyard.

1. What are the commitments to reduce diesel PM emissions?

UP shall meet the diesel PM emission reduction levels at the UP ICTF/Dolores Railyards by the specified compliance deadlines set forth in Table E-1 irrespective of receipt of public incentive funds. UP may, however, use incentive funds, if available, to achieve the emission reduction levels. This includes funds under Proposition 1B to replace, repower, or retrofit locomotives. To meet the 85 percent reduction level, ARB staff estimates that the railyard diesel PM emissions of 20.3 tons per year in 2005 will need to be reduced to about 3.0 tons per year by 2020.

Typical emission sources within the railyard affected by the diesel PM emission reduction levels in Table E-1 include interstate line haul locomotives, switch and medium horsepower locomotives, drayage trucks, cargo handling equipment such as cranes and yard hostlers, transport refrigeration units operated with drayage trucks or railcars, and stationary engines and maintenance equipment. Passenger locomotive emissions are excluded from the calculation of railyard diesel PM emissions and reductions used to determine compliance with Table E-1.

Table E-1. UP ICTF/Dolores Railyards
Diesel PM Emission Reduction Levels and Schedule

Compliance Deadline	Percent Diesel PM Reductions from 2005 Baseline*	Tons per Year Diesel PM Reductions from 2005 Baseline**
December 31, 2011	60 percent	12.2
December 31, 2013	65 percent	13.2
December 31, 2015	74 percent	15.0
December 31, 2017	75 percent	15.2
December 31, 2020	85 percent	17.3

* If, after the effective date of this program, ARB reduces the stringency or extends the effective date of ARB regulations affecting non-locomotive diesel PM emission sources at railyards, or U.S. EPA reduces the stringency or extends the effective date of its locomotive PM emission standards, the diesel PM emission reduction levels will be adjusted by ARB accordingly.
** Tons subject to revision if ARB updates the 2005 Baseline number.

ARB staff will use the emissions inventory reported in the 2005 Health Risk Assessment as the 2005 baseline, together with the comprehensive emission inventory submittals for subsequent years, to determine compliance with the Table E-1 emission reduction levels. If ARB revises the *ARB Railyard Emission Inventory Methodology* (2006), ARB staff will recalculate the 2005 Baseline and apply the percent diesel PM reduction listed in Table E-1 to update the associated tons per year of diesel PM reductions required by each compliance deadline. ARB staff will validate the inventory information through a thorough technical review of the data, ongoing ARB railyard inspections, ARB field surveys, and ARB tracking of locomotive and railyard operations.

2. Does growth change the commitments to reduce diesel PM emissions?

No. UP commits to reducing diesel PM emissions from the UP ICTF/Dolores Railyards by at least 85 percent by 2020 and meeting the intermediate levels in Table E-1, regardless of whether the proposed UP ICTF Modernization Plan is implemented and regardless of the potential increases in railyard activity levels, such as the number of container lifts.

3. How can UP reduce railyard diesel PM emissions 85 percent by 2020?

ARB's supporting analysis for feasible emission reductions at UP ICTF/Dolores Railyards is located in a separate document entitled, *Basis for Proposed Commitments to Reduce Diesel Particulate Matter at the UP ICTF/Dolores Railyards* (*Basis for Proposed Commitments:* June 2010*)*. This *Basis for Proposed Commitments* document describes possible options that could be implemented to achieve the Table E-1 diesel PM emission reduction levels.

In 2005, the railyard generated an estimated 20.3 tons per year of diesel PM emissions from freight operations. ARB staff estimates that existing U.S. EPA and ARB regulations and agreements will reduce diesel PM emissions at the railyard down to 4.6 tons per year by 2020 (a 77 percent reduction). ARB staff estimates that UP can further cut the railyard diesel PM emissions by 1.6 tons per year by 2020 (achieving an 85 percent reduction compared to 2005 levels).

The required diesel PM emission reductions from existing U.S. EPA and ARB regulations and agreements at the railyard will occur with or without implementation of the UP ICTF Modernization Plan. If the Modernization Plan is put into place, increases in locomotive emissions due to greater container volume would be largely offset by the near elimination of cargo equipment emissions through conversion of the equipment from diesel fuel to electric power.

4. What are the railroad commitments to prepare and submit emission inventories, air dispersion modeling, and emission reduction plans? What are the ARB commitments to publicly release the railroad documents and health risk assessments?

Table E-2 shows the schedule for UP to submit the railyard diesel PM emission inventories, air dispersion modeling, and draft and final emission reduction plans. Table E-3 identifies the dates by which ARB shall release the railyard diesel PM emission inventories, air dispersion modeling, health risk assessments, and the emission reduction plans for public review.

Table E-2. UP ICTF/Dolores Railyards
Schedule for UP Submittal of Documents: Emission Inventories, Air Dispersion Modeling, and Emission Reduction Plans

Calendar Year	Emission Inventory [a]	Air Dispersion Modeling	Draft Emission Reduction Plan	Final Emission Reduction Plan
2010	Dec 31, 2011 (I)	-------	-------	-------
2011	Apr 1, 2012 (C)	Jun 1, 2012	Sep 1, 2012	Dec 31, 2012
2012	Apr 1, 2013 (I)	-------	-------	-------
2013	Apr 1, 2014 (C)	Jun 1, 2014	Sep 1, 2014	Dec 31, 2014
2014	Apr 1, 2015 (I)	-------	-------	-------
2015	Apr 1, 2016 (C)	Jun 1, 2016	Sep 1, 2016	Dec 31, 2016
2016	Apr 1, 2017 (I)	-------	-------	-------
2017	Apr 1, 2018 (C)	Jun 1, 2018	Sep 1, 2018	Dec 31, 2018
2018	Apr 1, 2019 (I)	-------	-------	-------
2019	Apr 1, 2020 (I)	-------	-------	-------
2020	Apr 1, 2021 (C)	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.

Table E-3. UP ICTF/Dolores Railyards
Schedule for ARB Release of Documents: Emission Inventories, Air Dispersion Modeling, ARB Health Risk Assessments, and Emission Reduction Plans

Calendar Year	Railroad Emission Inventory [a]	Railroad Air Dispersion Modeling	ARB Health Risk Assessment	Railroad Draft Emission Reduction Plan [b]	Railroad Final Emission Reduction Plan [b]
2010	Jan 15, 2012 (I)	-------	-------	-------	-------
2011	Apr 15, 2012 (C)	Jun 15, 2012	Oct 1, 2012	Oct 1, 2012	Jan 15, 2013
2012	Apr 15, 2013 (I)	-------	-------	-------	-------
2013	Apr 15, 2014 (C)	Jun 15, 2014	Oct 1, 2014	Oct 1, 2014	Jan 15, 2015
2014	Apr 15, 2015 (I)	-------	-------	-------	-------
2015	Apr 15, 2016 (C)	Jun 15, 2016	Oct 1, 2016	Oct 1, 2016	Jan 15, 2017
2016	Apr 15, 2017 (I)	-------	-------	-------	-------
2017	Apr 15, 2018 (C)	Jun 15, 2018	Oct 1, 2018	Oct 1, 2018	Jan 15, 2019
2018	Apr 15, 2019 (I)	-------	-------	-------	-------
2019	Apr 15, 2020 (I)	-------	-------	-------	-------
2020	Apr 15, 2021 (C)	-------	-------	-------	-------

[a] (C) = Comprehensive Emission Inventory. (I) = Interim Emission Inventory.
[b] Following submittal of the draft and final emission reduction plan, ARB staff will provide a brief supplemental document that estimates the associated health risk for future compliance years.

a. Railyard Diesel PM Emission Inventories

i. Comprehensive Diesel PM Emission Inventories

UP commits to prepare the comprehensive diesel PM emission inventories for calendar years 2011, 2013, 2015, 2017, and 2020. UP shall prepare each comprehensive diesel PM emission inventory for the railyard in accordance with *ARB Railyard Emission Inventory Methodology* (2006) or its subsequent revisions, using data for the whole of that calendar year. The comprehensive diesel PM emission inventories will include, to the extent reasonably available, detailed activity information such as locomotive event recorder data, hours of operation for cargo handling equipment and transport refrigeration units, and drayage truck time in operation within the railyard. The comprehensive inventory will also identify activity and growth projections through 2020, and the basis for those projections.

ii. Interim Diesel PM Emission Inventories

UP commits to prepare interim diesel PM emission inventories for the railyard for calendar years 2010, 2012, 2014, 2016, 2018, and 2019, using data for the whole of the calendar year. The interim emission inventories will identify and utilize updates on locomotive usage, other equipment changes, and activity levels (e.g., number of lifts, drayage truck activities, locomotive shop releases, if applicable) to quantify changes to the last comprehensive diesel PM emission inventory. The interim inventory for calendar year 2010 will quantify changes to the comprehensive 2005 diesel PM emission inventory. ARB staff will use the interim emission inventories to consider if there are any potential issues with UP continuing to make sufficient progress in order to meet the railyard diesel PM emission levels specified in Table E-1.

b. Air Dispersion Modeling

UP commits to prepare air dispersion modeling based on the schedule in Table E-2. Air dispersion modeling is to be performed in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. UP also commits to provide source apportionment data for receptors defined in the air dispersion model and a source contribution analysis. UP also commits to analyze the impacts on the modeled air concentrations from significant updates to the modeling methodology, such as the current version of AERMOD model from U.S. EPA, the availability of updated meteorological data, or any other modeling parameters or inputs which could substantively affect the modeling estimations.

c. Health Risk Assessments

ARB staff commits to prepare health risk assessments using the comprehensive diesel PM emission inventories and air dispersion modeling results. The risk assessments are to be prepared in accordance with *ARB Health Risk Assessment Guidance for Railyard and Intermodal Facilities* (2006) or its subsequent revisions. The updated risk assessments will provide detailed information comparing excess cancer risks and non-cancer health effects with the estimates in the 2005 Health Risk Assessment. ARB staff will compare 2005 railyard emissions and associated health effects with risk assessment results for later years using the same or similar methodology, and also include a separate analysis for any subsequent changes in future year methodologies. ARB staff shall complete the health risk assessment reports for the railyard according to the schedule provided in Table E-3.

Following UP's submittal of the draft and final emission reduction plans, ARB also commits to provide a brief supplemental document to the public that estimates the associated health risk for future compliance years. If ARB's health risk estimates for the draft emission reduction plan do not project that health risk will continue to be reduced, ARB shall include that information in its written comments to UP on UP's draft emission reduction plan.

d. Emission Reduction Plans

UP commits to submit draft and final emission reduction plans according to the schedule in Table E-2. The emission reduction plans are to be based on the most recent railyard diesel PM emission inventories. The purpose of the plans is for UP to detail the actions it will take to reduce railyard emissions down to the levels shown in Table E-1 for the next compliance deadline, and the range of potential actions it intends to pursue for subsequent compliance deadlines. The emission reductions plans will document existing and projected railyard diesel PM emissions through 2020 (accounting for growth), describe changes in source category activities, identify existing and future actions to cut emissions and provide specific implementation schedules for these actions.

e. ARB Review

i. Diesel PM Emission Inventories and Air Dispersion Modeling

Within 20 calendar days of receipt of a railyard comprehensive or interim diesel PM emission inventory, or air dispersion modeling, ARB shall review the submission for completeness and accuracy and will notify UP of its findings. If ARB determines that the submission is not complete and accurate, it will, within the above 20-day time period, notify UP in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Upon receipt of a notice of deficiency from ARB, UP will within 15 calendar days correct the deficiencies and resubmit the submission to ARB. Within 10 calendar days, ARB will notify UP as to whether the submission is complete and accurate. If not, ARB will make a preliminary determination of non-compliance following the procedures set forth in Section 9.c.ii below.

ii. Emission Reduction Plans

Within 30 calendar days of receipt of a draft railyard emission reduction plan, ARB shall review the plan for completeness and accuracy and shall notify UP of its findings. If ARB determines that the draft plan is not complete and accurate, or that the draft plan, in ARB staff's opinion, cannot reasonably achieve the diesel PM reductions required by the next compliance deadline as set forth in Table E-1, ARB shall, within the above 30-day time period, notify UP in writing of any deficiency and the reasons therefor, and make such written notification publicly available.

Within 30 calendar days of receipt of the final plan, ARB shall notify UP as to whether the plan is complete, accurate, and can reasonably achieve the diesel PM emission reductions required by the next compliance deadline as set forth in Table E-1, and make sure such written notification is publicly available. If not, ARB shall make a preliminary determination of non-compliance as set forth in Section 9.c.ii below. Subsequently, if the administrative appeals panel fully or partially affirms the finding of ARB staff, UP will have 30 calendar days to submit to ARB a revised final plan for the next compliance deadline to cure any deficiencies upheld by the panel. If UP fails to submit a revised final plan or if ARB staff determines the revised final plan is still deficient, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of Section 9.

f. Commitment to Follow Through on Final Emission Reduction Plan

UP shall take the necessary actions identified in the final emission reduction plan in accordance with the plan's implementation schedules to meet the diesel PM emission reduction levels for the next compliance deadline as set forth in Table E-1. If UP determines that alternative actions not identified in its most recent plan should be implemented to achieve the emission reduction levels for the next compliance deadline, and the alternative actions materially alter the pathway for achieving the emission reductions in the plan, UP will within 15 days of its determination notify ARB of the alternative actions and the reasons for the changes.

5. What is the commitment for public meetings and outreach?

UP and ARB commit to hold a public meeting no later than December 15 of 2012, 2014, 2016, and 2018, with members of the surrounding community following the release of the most current ARB health risk assessment and UP draft emission reduction plan as specified in the Table E-3 schedule. At the public meeting, UP and ARB staff will seek public input on the available documents prior to ARB's final determination on the emission reduction plan.

6. What is the commitment to evaluate options for operational changes?

UP commits to evaluate and provide recommendations, if any, for the implementation of those changes in railyard operations that UP believes may significantly reduce railyard diesel PM emissions or changes in the location of the railyard emission sources that ARB believes may reduce health risk. UP shall evaluate potential changes at the UP ICTF/Dolores Railyards according to the following schedule, including:

- By December 31, 2012:
  - Installation of a stationary collection system to reduce locomotive maintenance and service related emissions.
  - Relocation of diesel-fueled yard tractors and transport refrigeration units.

- By December 31, 2013:
  - Relocation of the truck gate (part of the UP ICTF Modernization Plan)
  - Relocation of the locomotive maintenance and service facilities.
  - Electric infrastructure to support operation of rail mounted gantry cranes and stationary transport refrigeration units.

UP will conduct this one-time operational review considering, among other things, the potential diesel PM emissions reductions that could be achieved, the technical feasibility of such actions, the operational impacts on the railyard's throughput velocity and fluidity, safety, the availability of land and access, the costs and cost-effectiveness of such actions, and any railyard-specific factors at the UP ICTF/Dolores Railyards. Each operational option shall be analyzed, and recommendations, if any, for implementation will be completed as soon as possible for this railyard, but in any case not later than December 31, 2013. UP shall provide the assessment and any recommendations for implementation of operational changes to ARB, and ARB will make them publicly available.

ARB commits to support these efforts with technical assistance and to evaluate the impacts of each potential operational change on the maximum individual cancer risk for the railyard. ARB will make the results of this evaluation publicly available.

7. Will UP be able to access incentive funding to support these commitments?

UP, to the extent feasible, will compete for federal, State, local, and private incentive funding to supplement its capital expenditures, and to accelerate further diesel PM and NOx emission reductions at this railyard.

Consistent with State law and Board policies, ARB staff will support efforts by UP to seek a mix of federal, State, and local incentive funding to accelerate UP's ability to meet the diesel PM emission reduction levels for the railyard.

8. What are the provisions for UP and ARB to meet and confer?

UP agrees to meet and confer with ARB in 2013 regarding the progress being made by locomotive engine manufacturers to produce Tier 4 interstate line haul locomotives and the potential for interstate testing of prototype locomotives to include California.

UP agrees to meet and confer with ARB by 2018 to evaluate and explore opportunities for further diesel PM emission reductions by 2020 and beyond.

9. What are the mechanisms for ARB to enforce these commitments? What would trigger ARB to initiate regulatory action?

a. Potential ARB Actions to Enforce the Revised 2010 Commitments

Upon a final determination of the ARB Executive Officer, or if appealed, of the administrative appeals panel that UP has failed to meet its commitments set forth herein at Sections 1, 2, 4, 5, and 6, ARB commits to submit to the Board within four months from the date of the determined failure the following locomotive and railyard rulemakings:

- A regulation of switch and medium horsepower locomotives that are not preempted under federal law (e.g., locomotives that primarily operate in California and that were manufactured prior to 1973 or that exceed 133 percent of their useful life since original manufacture or last remanufacture, whichever is later).

- A designated railyard regulation that requires risk reduction audits and plans to achieve targeted emission reduction levels.

ARB will also consider the following actions:

- Pursue federal legislation to expand ARB authority to adopt regulations for in-use locomotives.

- Petition U.S. EPA to strengthen existing federal locomotive regulations.

ARB is designated as the agency responsible for enforcement of the UP commitments. The enforcement authorities specified herein may only be exercised by ARB. UP may, at any time, initiate informal consultations with ARB to identify and resolve concerns or other issues regarding compliance with its commitments herein.

In determining whether UP has met its commitments, ARB and UP (for purposes of this section, individually referred to as "a party" and collectively referred to as "the parties") agree to the following exclusive process.

b. ARB Verification of Railyard Diesel PM Emission Reduction Levels

To determine whether UP has met the UP ICTF/Dolores Railyards diesel PM emission reduction levels specified in Table E-1, ARB will review the comprehensive emission inventories and interim emission inventories in relation to information collected by ARB staff. ARB will conduct semi-annual railyard inspections, which will also be augmented by ARB photographic tracking and field surveys of railyard switch and medium horsepower locomotives. In addition, ARB staff will use the annual UP locomotive NOx fleet average agreement submittals to verify the number and tier of interstate line haul locomotives operating within the South Coast Air Basin. ARB staff will also randomly conduct inspections of UP interstate line haul locomotives entering and exiting the

South Coast Air Basin to help assess compliance with the Table E-1 diesel PM emission reduction levels.

c. Preliminary Determination of Non-Compliance

i. Failure to Comply with the Railyard Diesel PM Emission Reduction Levels

Within 30 working days of receipt of the comprehensive railyard diesel PM emission inventories, ARB shall make a written preliminary determination notifying UP as to whether UP met or failed to meet the diesel PM emission reduction levels specified in Table E-1 for the previous year. If ARB determines that UP has failed to meet its emission reduction levels, ARB shall within the same 30 working days provide UP with its written preliminary determination, which will set forth the reasons for its findings. ARB will, with the greatest precision possible based on data submitted by UP, calculate the difference between the railyard diesel PM emission reduction level reported by UP and the levels required in Table E-1. ARB and UP shall use their respective best efforts to expedite submission and review of the reports. The time periods provided for ARB to make a preliminary compliance determination may be extended by written agreement between ARB and UP.

Within 15 calendar days of receipt of ARB's preliminary determination that UP has failed to meet the emission reduction levels, UP may request to meet and confer with ARB and/or provide ARB with such information and analysis as UP believes appropriate to demonstrate its compliance with the Table E-1 diesel PM emission reduction levels. If a meet and confer is requested, the parties shall meet within 10 working days of the request. Within 15 calendar days after receipt of UP's response or after meeting and conferring with ARB, ARB shall review and consider the information provided by UP and make a final determination, in writing, as to whether UP has failed to meet the Table E-1 diesel PM emission reduction levels. ARB will make such final written determination publicly available.

For the Table E-1 compliance deadlines in 2011, 2013, 2015, 2017, or 2020, if ARB staff determines that UP missed its percentage target for the UP ICTF/Dolores Railyards by not more than 2 percent (e.g., reaching a 73 percent compliance level where 75 percent was required), UP will be given the opportunity to cure this deficiency by the next calendar year, provided it demonstrates the new compliance level by conducting a full inventory analysis. Failure to conduct the analysis or failure to cure the deficiency in the following calendar year shall constitute a failure to meet the appropriate targets in Table E-1.

ii. Failure to Comply with Other Railyard Commitments

If ARB makes a preliminary determination that UP has failed to meet any other of its commitments set forth herein, ARB shall notify UP, in writing, of its findings. Within 15 calendar days, UP may request to meet and confer with ARB and/or provide ARB

with such information and analysis as UP believes appropriate to demonstrate its compliance. If a meet and confer is requested, the parties shall meet within 10 working days of the request.

Within 15 calendar days after receipt of UP's response or after meeting and conferring with ARB, ARB will review and consider the information provided by UP and make a final determination, in writing, as to whether UP has failed to meet any of its non-emission reduction-related commitments. ARB will make such final written determination publicly available.

d. Final Determination by ARB of Non-Compliance

A final determination of non-compliance shall specifically identify the reasons why ARB has found UP not to be in compliance with agreed-upon commitments. A final determination of non-compliance for failure to meet the emission reduction levels set forth in Table E-1 will provide ARB's final calculations of the emission reduction levels of the UP ICTF/Dolores Railyards. Findings of UP's failure to meet other commitments shall set forth in detail ARB's determination of why the commitments have not been met. ARB will publicly post its final determination notice of non-compliance on its website and make available such notice on a list serve that will be established for notifying the public about compliance with the railyard emission reduction commitments.

e. Dispute Resolution

In the event of a dispute concerning an ARB final determination of non-compliance or any dispute arising between ARB and UP concerning their respective commitments, the party asserting the dispute shall provide notice to the other party and set forth the issues underlying the dispute. The parties shall meet and confer regarding the identified issues within 15 working days after receipt of notification, and if they cannot reach agreement within 15 working days after such consultation, shall submit their respective positions to an administrative appeals panel, which shall consider the matter as expeditiously as possible. Except for confidential trade secret information, ARB will publicly post on its website and make available by the aforementioned list serve all documents submitted by the parties to the administrative hearing panel. ARB will also post and make available a notice that interested persons may submit written statements of position and supporting documentation to the administrative appeals panel that will be made part of the record of the hearing.

i. Composition of Administrative Appeals Panel

The panel shall be comprised of one member selected by ARB, one member selected by UP, and a third member selected by the initial two members from a list of five or more persons that the parties shall agree to within 120 calendar days of their exchange of commitment letters. The list shall include persons qualified to hear matters that are likely to be heard by the dispute resolution panel. From the list of five or more persons, the parties shall select the person most readily available to hear the matter within

30 calendar days (or as soon thereafter as possible) from the date that the person is contacted by either the ARB or UP panel member. If no person from the previously selected list is available to hear the matter within 45 calendar days of being notified, the ARB and UP panel members shall contact an arbitration referral service, identify the matter(s) at issue and accept from the service a list of five persons who are qualified to hear the matter(s) at issue and are readily available. The two panel members selected by the parties may mutually agree on one of the five persons to serve on the panel, but if they cannot agree, each panel member will alternatively strike one person from the list until just one person remains. The two panel members selected by the parties will serve as technical advisors to the third panel member, who shall serve as the presiding member of the panel and who shall be solely responsible for making the final decision on behalf of the panel.

ii. Administrative Appeals Panel Process

Unless otherwise determined that the matter(s) at issue require oral testimony, the panel shall make its decision based upon the written submissions of ARB and UP and any written statements submitted by interested persons (see below). If a hearing to take testimony is determined to be necessary, the hearing shall be public. The panel shall determine the time and place of the hearing, and will set forth the procedures to be followed at the hearing. The panel will take all precautions necessary to preserve the confidentiality of trade secret or other confidential information, and will consider such evidence in a closed meeting.

iii. Public Comments to Administrative Appeals Panel

Interested persons may submit written statements and supporting documentation to the panel regarding the matter(s) at issue before the matter(s) are taken under submission, however, only ARB and UP shall be parties to the dispute resolution process.

iv. Final Decision by Administrative Appeals Panel

The panel presiding member shall issue his or her final decision on behalf of the panel within 30 calendar days from the date that the matter is submitted to the panel. While either party receiving an adverse decision from the panel may seek expedited review of the decision in the Superior Court for the County of Sacramento, if the panel's decision upholds the Executive Officer's final determination of non-compliance, ARB may immediately commence the rulemaking process outlined in the opening paragraphs of this section. If judicial review is not sought, then the decision of the panel will be binding on ARB and UP, as well as any interested person or Intended Beneficiary of the Revised 2010 Commitments (see below).

v. Costs and Fees

Each party to the proceedings outlined above will bear its own costs and fees, with the exception that the parties agree to split all costs and fees arising from the employment of the third panel member.

10. What are the rights of residents near railyards to enforce ARB's Revised 2010 Commitments?

a. Rights of Persons Other Than ARB and UP

Residents living within two miles of the UP ICTF/Dolores Railyards are the intended beneficiaries (Intended Beneficiaries) of these Revised 2010 Commitments and are entitled to bring an action in mandamus in the Superior Court of Sacramento against ARB to ensure that ARB meets its commitments under the Revised 2010 Commitments.

The Intended Beneficiaries will be bound by the outcomes of all dispute resolution processes engaged in by ARB and UP. If UP fails to meet its commitments under the Revised 2010 Commitments, only ARB has the right to exercise the provisions of Section 9, which are the exclusive remedies provided under the Revised 2010 Commitments for non-compliance by UP. Except as provided in Section 10, the Revised 2010 Commitments do not create any new rights, including the right of enforcement, for any person (including Intended Beneficiaries) or entity other than ARB or UP.

b. Notice and Opportunity to Cure

To provide ARB with an opportunity to cure or otherwise address an alleged failure by ARB to meet one of its commitments under the Revised 2010 Commitments, Intended Beneficiaries shall provide ARB with at least 45 days written notice of its intent to seek an order of mandamus from the Superior Court of Sacramento. The notice shall identify the alleged failure, the harm caused by the alleged failure, and the factual basis supporting the allegation. If ARB receives such a notice, ARB shall forward a complete copy to BNSF Railway (BNSF) and UP within five working days and shall within a reasonable period of time thereafter notify BNSF, UP, and the Intended Beneficiaries who provided ARB with notice of the pending action as to whether ARB has been able to cure (or is in the process of curing) the alleged failure or whether the alleged failure is incurable in ARB's view.

If ARB fails to cure or to take reasonable steps towards promptly curing the alleged failure within 45 days after receiving notice, the Intended Beneficiaries may proceed to file above-referenced mandamus action in the Superior Court of Sacramento.

11. How will UP handle the disposition of any pre-Tier 0 locomotive formerly based in the UP ICTF/Dolores Railyards?

UP shall not reassign any pre-Tier 0 locomotive formerly based in the UP ICTF/Dolores Railyards to another railyard in California.

12. What are the requirements if UP is considering withdrawal from these Revised 2010 Commitments?

The parties are pledged to successful implementation of the Revised 2010 Commitments. UP will meet and confer with ARB prior to any action to withdraw from these Revised 2010 Commitments. UP and ARB may mutually elect to amend the Revised 2010 Commitments to withdraw or modify specific provisions. If a reasonable resolution cannot be achieved, UP may withdraw from the Revised 2010 Commitments as specifically provided below.

a. ARB Action Prior to Meeting the Requirements of Section 9

If ARB proceeds with the rulemakings or other actions identified in Section 9.a. prior to a final determination of UP non-compliance with the Revised 2010 Commitments, UP may withdraw from these Commitments.

b. Other Reasons

If either of the following actions occurs, UP may also withdraw from the Revised 2010 Commitments, but UP shall continue to comply with Section 13 to maintain progress through December 31, 2020:

- ARB invokes its remedies under Section 9.a. according to the process prescribed in Section 9.

- An agency of the federal government, the State of California (other than ARB), or a local subdivision of the State of California enacts, mandates, or requires UP to perform an action at the UP ICTF/Dolores Railyards or affecting this railyard that is identical or substantially similar to actions required to meet these Revised 2010 Commitments. However, actions taken by the City of Los Angeles Harbor Department, the City of Long Beach (acting by and through its Board of Harbor Commissioners), or the Intermodal Container Transfer Facility – Joint Powers Authority related to implementation of the San Pedro Bay Ports Clean Air Action Plan or approval of a new railyard or expansion of an existing railyard do not constitute grounds for UP to withdraw from these Revised 2010 Commitments.

13. How will UP maintain the progress already made at the UP ICTF/Dolores Railyards if UP withdraws from these Revised 2010 Commitments?

UP agrees to do all of the following in the event that UP withdraws from these Revised 2010 Commitments at the UP ICTF/Dolores Railyards for any reason other than that specified in Section 12.a.:

- Through December 31, 2020, substantially maintain the emission reductions required by Table E-1 that were achieved by implementation of these Revised 2010 Commitments at the UP ICTF/Dolores Railyards through the last compliance deadline. From the date that Section 13 is triggered, subsequent growth in railroad operations is excluded from this provision.

- Through December 31, 2020, provide a report to ARB for the UP ICTF/Dolores Railyards that demonstrates maintenance of progress as described above. UP shall provide this report every other year, beginning two years following the date of withdrawal.

14. What are the general meet and confer provisions?

In order to assure successful implementation of these Revised 2010 Commitments, UP and ARB may at any time meet and confer to review accomplishments, to assess any implementation issues, or to determine if any changes are necessary to improve the overall effectiveness of the Revised 2010 Commitments.

15. What are the rights of ARB and UP notwithstanding these Revised 2010 Commitments?

Nothing in this agreement precludes ARB from developing regulations within its authority as required to achieve the goals of the State Implementation Plan and Climate Change Scoping Plan.

UP is implementing its commitments notwithstanding the preemptive effect of the federal Interstate Commerce Commission Termination Act ("ICCTA"), the Clean Air Act, the Commerce Clause and other federal law. UP and ARB recognize that railroads are to a significant degree regulated by federal law, and that aspects of State and local authority to regulate railroads, rail operations, and locomotives are preempted. By executing and performing the Revised 2010 Commitments, UP and ARB agree that there is no waiver or modification of any aspect of federal preemption or setting of any precedent as to preemption, reservation of rights or voluntary compliance with other commitments, rules or agreements.

If ARB proceeds with the rulemaking or other actions identified in Section 9.a., UP reserves all legal and procedural rights to contest said rulemakings or actions.

16. What constitutes the full understanding of the Parties?

This document constitutes the full understanding and agreement of ARB and UP with respect to the UP ICTF/Dolores Railyards regarding the subject matter of the Revised 2010 Commitments. ARB and UP have voluntarily entered into the Revised 2010 Commitments, and nothing in the Revised 2010 Commitments affects the scope of ARB's regulatory authority or the scope of preemption under federal law. ARB and UP agree that no amendment to the Revised 2010 Commitments shall be binding unless in writing and signed by authorized representatives of ARB and UP.

These Revised 2010 Commitments do not revoke, reduce, amend, or modify the undertakings of UP in any previous agreements which remain in effect on the date of this document.

17. What are the effective dates of these Revised 2010 Commitments?

These Revised 2010 Commitments shall take effect upon execution by both parties and remain in effect until December 31, 2020 unless amended by ARB and UP.

IN WITNESS WHEREOF, the parties have executed these Revised 2010 Commitments.

CALIFORNIA AIR RESOURCES BOARD, an agency of the State of California	THE UNION PACIFIC RAILROAD COMPANY, a Delaware corporation
James N. Goldstene Executive Officer	Lance M. Fritz Executive Vice President of Operations
Date	Date
Address for notice: 1001 "I" Street P.O. Box 2815 Sacramento, CA 95812	Address for notice: 1400 Douglas Street Omaha, NE 68179

APPENDIX F

CALIFORNIA ENVIRONMENTAL QUALITY ACT FUNCTIONAL EQUIVALENT DOCUMENT

Revised 2010 Commitments Between the Air Resources Board and Union Pacific Railroad and BNSF Railway to Further Reduce Diesel Particulate Emissions at Four High-Priority Railyards

July 5, 2011

California Air Resources Board
P.O. Box 2815
1001 "I" Street
Sacramento, CA 95812

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PREFACE

This document constitutes the Functional Equivalent Document ("FED") for proposed Revised 2010 Commitments Between the Air Resources Board and Union Pacific Railroad and BNSF Railway to Further Reduce Diesel Particulate Emissions at Four High-Priority Railyards (Revised 2010 Commitments).

Interested members of the public may present comments on this Functional Equivalent Document in writing. The public comment period will be for 45 days from July 5, 2011 to August 19, 2011. Comments may be submitted by postal mail or by electronic mail addressed to the following:

Postal mail: Air Resources Board, SSD/Freight Transport Branch – 6th Floor, Attn: Harold Holmes, 1001 I Street, Sacramento, California 95814

Electronic submittal: on the ARB website for the Revised 2010 Commitments at http://www.arb.ca.gov/railyard/commitments/commitments.htm.

Please note that under the California Public Records Act (Government Code §6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request. Additionally, this information may become available via Google, Yahoo, and any other search engines.

A written response to comments raising significant environmental issues will be prepared and approved by the Executive Officer and posted on the website at http://www.arb.ca.gov/railyard/commitments/commitments.htm prior to final action on the Revised 2010 Commitments.

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Appendix F
California Environmental Quality Act Functional Equivalent Document

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EXECUTIVE SUMMARY OF APPENDIX F

Staff of the California Air Resources Board (Board or ARB) is proposing approval of a set of voluntary, but binding, agreements, called the *Revised 2010 Commitments Between the Air Resources Board and Union Pacific Railroad and BNSF Railway to Further Reduce Diesel Particulate Emissions at Four High-Priority Railyards* ("Revised 2010 Commitments" or "Commitments") to reduce the health risk to communities near these railyards. The four railyards are BNSF San Bernardino and Hobart Railyards, and the UP Commerce and ICTF/Dolores Railyards. The Revised 2010 Commitments were developed in consideration of public testimony and Board direction provided at the September 2009, February 2010, and June 2010 Board meetings, as well as community meetings.

The primary project objective is to reduce air emissions of diesel particulate matter (PM) from operations at the four high-priority railyards, beyond the levels expected under the existing program of adopted regulations and agreements, and specifically to achieve at least an 85 percent reduction in diesel PM emissions at each railyard between 2005 and 2020, regardless of growth in activity or operations. The Revised 2010 Commitments would establish enforceable emission caps and other requirements, tracking mechanisms and deadlines to achieve the diesel PM reductions over the next ten years. In 2020, the benefits attributable to the Revised 2010 Commitments alone are about 12.5 tons per year reduction in diesel PM at the four railyards combined. This translates to about a 30 to 70 percent reduction in the excess cancer risk in 2020 from operations at each railyard.

Staff is proposing these voluntary agreements because they are the most effective and most certain way to achieve substantial new emission reductions from the locomotives that ARB cannot regulate. ARB has already regulated the railyard sources under its direct authority, including drayage trucks, cargo handling equipment, transport refrigeration units, and diesel fuel.

However, ARB lacks authority to regulate the emissions of late-model or remanufactured locomotives that contribute the majority of railyard emissions in future years. Under the federal Clean Air Act, ARB can regulate only the oldest locomotives, which no longer regularly operate in these four high-priority railyards.

A. Environmental Review Process

1. California Environmental Quality Act

The California Environmental Quality Act (CEQA) and ARB regulations require an analysis to identify any potentially significant adverse environmental impacts of ARB's regulations and projects. ARB has determined that execution and implementation of the proposed Revised 2010 Commitments constitutes a "project" as defined by CEQA.[1]

ARB is the lead agency for this project. ARB has prepared this substitute functional equivalent document (FED) in accordance with CEQA and its certified regulatory program. Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a substitute document in lieu of formal CEQA documents such as initial studies, negative declarations and environmental impact reports once the Secretary of the Resources Agency has certified the regulatory program. The Secretary for the California Natural Resources Agency determined that ARB meets the criteria for a certified State regulatory program.[2]

As required by ARB's certified regulatory program, and the policy and substantive requirements of CEQA, this document presents ARB's assessment of reasonably foreseeable significant long- or short-term adverse and beneficial environmental impacts of the proposed action, and a succinct analysis of those impacts.[3] This document also addresses any feasible mitigation measures and feasible alternatives to the proposed action.

A 45-day public review period is provided for public review and comment on the FED. In accordance with ARB's certified regulatory program, all significant environmental issues raised during this comment period will be responded to in writing and considered prior to final action. A notice of final action and the written responses to comments shall be on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection.[4]

2. Scope of Analysis

Although the primary focus of conventional CEQA impact assessment is identification and disclosure of adverse environmental impacts, ARB's regulations require the assessment of both beneficial and adverse environmental impacts.[5] The Revised 2010 Commitments establish a performance standard based on the level of emissions for future years that cannot be exceeded regardless of growth in cargo or railyard activity.

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[1] Public Resources Code, §21000 et seq.; Title 14, California Code of Regulations, (CEQA Guidelines) §15378.
[2] CEQA Guidelines, §15251, subd. (d).
[3] Title 17, California Code of Regulations, §60005.
[4] Title 17, California Code of Regulations, §60007.
[5] Title 17, California Code of Regulations, §60005.

These levels are based on a specific percent reduction from established 2005 emissions. The railroads will accelerate the use of cleaner technology, possibly in combination with operational improvements, to achieve the required emission reductions at each railyard. These actions will help reduce the health risk in communities near the railyards.

For this project, potential effects on the environment were considered in terms of possible responses by the participating railroads at the four high-priority railyards. ARB staff evaluated possible actions the railroads could take to reduce emissions. The Revised 2010 Commitments are designed to be performance-based rather than prescriptive to gain the support from the railroads that is essential for voluntary agreements. The railroads have repeatedly stated that they will not participate in an agreement that directs or potentially constrains how they may conduct their operations, or an agreement that defines exactly how they must reduce diesel PM emissions.

Because there is inherent flexibility in the Revised 2010 Commitments, in that the commitments do not stipulate specifically how the railroads must comply, particular actions by the railroads cannot be predicted with certainty. However, for purposes of this assessment, staff focused on operational changes that could occur at the four high-priority railyards and any potential adverse environmental impacts associated with such changes. It is important to note that the railroads may choose or not choose to implement any of these responses for any number of reasons.

This analysis of indirect impacts of implementing the Revised 2010 Commitments is necessarily general, programmatic and qualitative in nature. A more detailed analysis is not reasonably feasible at this time because it is unknown what specific future actions will be taken at each railyard to meet the emission reduction targets.

An environmental checklist (Appendix F - Attachment 1) was used to identify the basis for assessing potentially significant adverse impacts associated with potential operational changes at each of the four railyards. Staff's review identified three topics for further review in the FED:

- Aesthetics
- Noise
- Transportation and Traffic

The checklist analysis determined that the remaining environmental topics would not be significantly adversely affected by the proposed project because the project will not involve any changes to the environment that could result in any potentially significant impacts on these resource areas. These include:

- Air Quality
- Agriculture Resources
- Biological Resources

- Cultural Resources
- Geology/Soils
- Greenhouse Gas Emissions
- Hazards and Hazardous Materials
- Hydrology and Water Quality
- Land Use and Planning
- Mineral Resources
- Population and Housing
- Public Services
- Recreation
- Utilities and Service Systems

These topics are not discussed in detail in the FED. The FED checklist in Attachment 1 provides a brief explanation supporting the determination for each of these resource areas that the project will have no impact. The FED also includes a discussion of beneficial impacts as required by ARB's regulations.[6]

B. Summary of Impacts Analysis

Below is a brief summary of the beneficial impacts and the environmental impacts analysis for each of the topics evaluated in the FED. The beneficial impacts would occur from railroad introduction of cleaner equipment to meet the emission reduction targets in the Revised 2010 Commitments. Virtually all of the potential adverse environmental impacts are directly tied to the possibility of railyard operational changes, which community members urged ARB to include in the agreements. Some of these changes could potentially shift the existing noise, light, or traffic impacts of current railyard activities from one set of nearby residents to another set of residents if operations are relocated within the railyard. It is important to note that the railroads may choose or not choose to implement any of these types of operational changes for any number of reasons.

1. Summary of Beneficial Impacts

With existing agreements and regulations described in Chapter III.B., ARB staff estimates that, after accounting for growth, UP and BNSF will reduce diesel PM emissions at the four high-priority railyards by about 50 to 80 percent from 2005 levels by 2020. The Revised 2010 Commitments require further reductions in diesel PM emissions at the four high-priority railyards. With the Revised 2010 Commitments, the projected 2020 diesel PM emissions at the four high-priority railyards will be reduced by an additional 30 to 70 percent.

[6] Title 17, California Code of Regulations, §60005.

The emission reductions under the Revised 2010 Commitments will reduce the related cancer and health risk from exposure to those emissions. As the railroads replace older interstate locomotives or upgrade the engines in those locomotives to Tier 4 levels to meet the diesel PM levels required by the Revised 2010 Commitments, staff anticipates that communities across the State that are not near the four high-priority railyards would receive about 15 percent of the benefits from the lower-emission locomotives brought in to meet the emission levels at the high-priority railyards. With Tier 4 locomotives, NOx, and HC will be concomitantly reduced by about 85 to 95 percent compared to Tier 0 levels.

2. Summary of Impacts Analysis by Resource Area

It is unknown at this time what specific operational changes, if any, will be taken at each railyard. However, possible operational changes could involve changes in locations of lights, noise, aesthetics, and transportation patterns and possibly lead to significant environmental impacts. Staff believes that there is a small probability of significant impacts that could result from changes in railyard operations, and that it is more likely that changes could result in benefits (e.g., quieter locomotives, fewer locomotives that are more powerful to do the same work, etc.).

a. Aesthetics

The Revised 2010 Commitments themselves do not recommend or propose any future changes that would result in changes in lighting or glare. It is unknown at this time what specific operational changes, if any, will be taken at each railyard. However, possible operational changes could involve changes in locations of particular lights at a railyard.

ARB staff does not anticipate that potential changes in operations would lead to changes in light and glare because the railyards are already substantially lighted and any movement of individual lights are not expected to change the existing light and glare from these sights. Although considered unlikely, it is possible that a railroad could shift operations in a way that affects lighting and glare at any of the affected yards. In view of the uncertainty about future actions that could affect light and glare, this analysis takes a conservative approach and considers these impacts to be potentially significant.

b. Noise

The Revised 2010 Commitments will not lead to changes in how the railroads comply with existing noise regulations. ARB anticipates that noise will decrease in response to the Revised 2010 Commitments, as railroads will need to deploy new and upgraded lower-emitting locomotives in significant numbers to meet the declining emission levels. These lower-emitting locomotives are quieter than the current models. Staff also anticipates the possibility that some of the existing diesel cargo handling equipment at railyards (such as cranes and yard trucks) may be replaced with fully electric models that are noticeably quieter.

The Revised 2010 Commitments would not increase the total noise at a railyard, but may change the location of some existing noise sources within the railyard. As a result of operational changes, noise from a maintenance facility or cargo handling equipment operation could be moved to a different location within a railyard.

It is unknown at this time what specific operational changes, if any, will be taken at each railyard. Therefore, ARB cannot predict at this time what potential noise impacts could arise from operational changes, including movement of a maintenance facility. In view of the uncertainty of possible noise impacts arising from such an operational change, this analysis takes a conservative approach and considers this to be a potentially significant impact.

c. Transportation and Traffic

The Revised 2010 Commitments would not increase the total transportation activities at a railyard, but may change the location of some existing transportation patterns for trucks and other mobile sources to enter and exit the railyard. As a result of operational changes, transportation corridors like truck gate entrances and exits onto nearby arterial roads could be moved to a different location within a railyard.

It is unknown at this time what specific operational changes, if any, will be taken at each railyard. Therefore, ARB cannot predict at this time what potential transportation impacts could arise from operational changes, including movement of a truck gate entrance or exit. In view of the uncertainty of possible transportation impacts arising from such an operational change, this analysis takes a conservative approach and considers this to be a potentially significant impact.

3. Summary of Cumulative Impacts

Based on ARB's review of the related projects and projected development in the area of the four high-priority railyards, staff does not anticipate the incremental effect or impact of the identified potential aesthetics, noise, and transportation and traffic impacts, when added or combined with adopted projections within the area and other recent and future closely related projects, to be cumulatively considerable. However, because it is

unknown what future changes may be undertaken and what development may occur in the area of the railyards that could combine with the railyards' potential impacts, and because the potential aesthetics, noise, and transportation and traffic impacts from the railyards may not be mitigated to a less-than-significant level, this analysis takes a conservative approach and considers the cumulative impacts to be potentially significant. ARB cannot identify feasible mitigation for potential aesthetics, noise, and transportation impacts, so these potential cumulative impacts remain significant and unavoidable.

C. Summary of Project Alternatives Evaluated

1. Alternative A: No Project

A "No Project" alternative, in this case, would be for ARB and UP and BNSF to not sign and implement the 2010 Railyard Commitments. The No Project alternative would mean the continued implementation of existing U.S. EPA and ARB regulations and agreements from 2005 to 2020. As shown in Tables F-3 through F-6 in Chapter IV, ARB staff estimates that UP and BNSF will reduce diesel PM emissions at the four priority railyards under the existing program by 50 to 80 percent by 2020, compared to 2005 levels. The level of emission reductions under the existing program could be less if growth in cargo activity is high. In contrast, the Revised 2010 Commitments would require UP and BNSF to reduce diesel PM emissions at the four high-priority railyards 85 percent by 2020, compared to 2005 levels, regardless of the growth in cargo activity. The No Project alternative does not even partially satisfy the project objective to achieve reductions beyond the existing program. Although the No Project alternative would not result in the potential adverse impacts associated with operational changes, it would prolong higher diesel PM emissions and associated health risks for residents living near the four high-priority railyards.

2. Alternative B: ARB Regulation for Non-Preempted Freight Locomotives

Under this alternative, ARB would adopt a statewide regulation requiring at least the major Class I railroads (BNSF and UP) to replace, retrofit, or upgrade any non-preempted locomotives operating in California to achieve more stringent California emission standards. For the regulation to take effect, ARB would need to obtain authorization from U.S. EPA to enforce the regulation under CAA §209(e)(2). Those locomotives and locomotive engines that are not preempted include those that were manufactured prior to 1973 and have not been upgraded (remanufactured) after 2000, and all locomotives that have exceeded 133 percent of their useful life since original manufacture or remanufacture, whichever is later.

Railroads could remove locomotives from the scope of the regulation by (1) converting an arguably non-preempted locomotive to a preempted locomotive by remanufacturing it to meet the minimum U.S. EPA Tier 0+ emission standard or (2) removing the older locomotive from California service and replacing it with a preempted locomotive

(i.e. Tier 0 or Tier 0+) from another state. As a result, there is a range of potential emission reductions that could result from ARB adoption and implementation of such a regulation. On the low end, the diesel PM benefits could be zero if BNSF and UP choose to replace all of the 80 remaining pre-Tier 0 locomotives in California with federally preempted Tier 0 locomotives from other states, because there is no change in PM emission levels between those standards. If BNSF and UP remanufactured the entire existing California fleet of 80 pre-Tier 0 switch and medium horsepower locomotives to comply with an ARB regulation, the remanufacture would have to meet U.S. EPA Tier 0+ standards under federal law. Thus, the resulting benefits would be approximately 0-16 tons of PM per year statewide. There would be virtually no benefits realized at the four high-priority railyards because there are no non-preempted locomotives in routine operation at these railyards.

Although this alternative would not be expected to generate potential adverse impacts on aesthetics, noise, and transportation and traffic, it would not meet the project objectives. This alternative would provide virtually no diesel PM emission reductions within the four high-priority railyards, because there are no non-preempted locomotives in routine operation in these railyards, and potentially no diesel PM emission reductions within the rest of the South Coast Air Basin and the rest of the State. Under this alternative, the diesel PM reductions that could be potentially realized in the South Coast Air Basin and the rest of the State could be subject to a legal challenge by the railroads. As a result, staff found that an ARB non-preempted locomotive regulation would achieve little, if any, of the diesel PM emission reductions required in the Revised 2010 Commitments.

3. Alternative C: ARB Regulation Requiring Zero-Emission Cargo Handling Equipment Operating at Intermodal Railyards

Under this alternative, ARB could consider amending the existing statewide regulation for cargo handling equipment operating at ports and intermodal railyards to require certain equipment at intermodal railyards to meet zero-emission levels on site, essentially through electrification of certain operations.

Under such a proposal, the ARB regulation could be amended to require the replacement of nearly all of the existing diesel cargo equipment that moves containers, including existing diesel rubber tired gantry cranes (RTGs), diesel yard tractors and forklifts/picks with electrified rail mounted gantry (RMG) cranes and the installation of the necessary RMG electric infrastructure at covered railyards. While existing diesel RTGs, yard tractors, and forklifts/picks are capable of operating anywhere in the railyard to move containers, an electric RMG is a very large overhead crane mounted on fixed guides that transfers a container between the railcar and the truck. These RMGs are installed in single, fixed location between the rail tracks and the container storage area.

This alternative would result in a reduction in noise at all four railyards. It may also result in short-term construction-related impacts on noise, air quality, and traffic at all

four yards, but the nature and scope of these impacts are unknown at this time. This alternative may result in a potential ongoing impact on transportation and traffic at the BNSF San Bernardino Railyard if a bridge is moved to accommodate a new electric crane.

If ARB staff proposed and the Board adopted a regulatory amendment to implement this alternative consistent with State and federal law, the maximum possible estimate of diesel PM emission reductions achievable at the four high-priority railyards would be less than 2.6 tons per year at a cost of well over $1.1 billion. However, some of those emissions would remain but be transferred to the communities where the electric power is generated for use at the railyards. As California transitions to more renewable and zero-emission sources to generate electric power, that impact would be expected to diminish.

This alternative would generate potential adverse impacts similar to those of the proposed project. However, compared to the proposed project, this alternative would be substantially less effective at achieving the project objective at the four high-priority railyards, with a maximum of 2.6 tons per year of diesel PM reductions in 2020 versus 12.5 tons per year of additional diesel PM reductions achievable in 2020 with the Revised 2010 Commitments.

4. Alternative D: ARB Regulation Requiring Railroads to Prepare Risk Reduction Audits, Plans, and Measures

Under this alternative, the Board could consider adopting a regulation to require railyards to perform risk reduction audits and plans, and implement measures to reduce railyard risks, similar to the existing requirements under Health and Safety Code "Hot Spots" program that applies to stationary sources and is overseen and enforced by the local air quality management and air pollution control districts.[7]

This alternative would be less effective in meeting the project objective than the Revised 2010 Commitments because any requirements to reduce the health risk from the high-priority railyards would need to exclude the diesel PM emissions from preempted locomotives, the largest remaining emission source in the four high-priority railyards. The maximum remaining diesel PM emissions in 2020 subject to control under this alternative would be 7.4 tons per year for all of the four railyards combined. If all of these on-site emissions were eliminated through electrification, it would still be substantially less effective than the 12.5 tons per year of diesel PM reductions achievable under the Revised 2010 Commitments.

Similar to Alternative C, Alternative D would be likely to result in reconfiguration at the railyards to enable installation and operation of electric rail mounted gantry cranes. Thus, this alternative would result in a longer-term reduction in noise at all four railyards, as well as potential short-term construction-related impacts and potential traffic impacts.

[7] Health and Safety Code §44300 et seq.

Therefore, this alternative would incur potential adverse environmental impacts substantially similar to the potential adverse environmental impacts of the Revised 2010 Commitments.

D. Conclusion

The purpose of the alternatives analysis is to determine whether or not a variation of the proposed project would reduce or eliminate significant project impacts, within the basic framework of the project objectives. Each of the four alternatives analyzed (Alternative A: "No Project," Alternative B: an ARB regulation for non-preempted locomotives, Alternative C: an ARB regulation for zero-emission cargo handling equipment at intermodal railyards, and Alternative D: an ARB regulation for railroad risk reduction audits, plans, and measures) would result in significantly less diesel PM emission reductions at the four high-priority railyards than the proposed project.

Alternatives A and B would not satisfy the project objective at all. Alternatives C and D would be less effective at meeting the project objective and would involve operational changes that share the same potential environmental impacts with the proposed project without reducing them. There are also serious questions about legal authority, costs, and technical feasibility associated with implementation of these alternatives as compared to the proposed Revised 2010 Railyard Commitments.

I. DOCUMENTS INCORPORATED BY REFERENCE

This FED analysis relies on substantial work done by ARB staff and the railroads to quantify the emissions of diesel PM at each of the four high-priority railyards and assess the resulting human health risk to residents living near each of the four railyards. Each of the eight inventory and health risk assessment documents has been previously published, and has been discussed at community meetings near the applicable railyard.

This analysis also relies on a comprehensive August 2009 ARB report on the technical options to reduce diesel PM emissions from rail operations, and a companion set of September 2009 staff recommendations to the Board on strategies to pursue. Staff's approach to the Revised 2010 Commitments considers comments from the Board and the public in response to presentations at meetings of the Board in 2009 and 2010.

Finally, this analysis builds on the work done for the *June 2010 Staff Report*, as well as this *Supplement to the June 2010 Staff Report* that responds to Board direction for additional evaluation.

All of these published documents are cited below, posted on ARB's railyard program website at the locations noted, and hereby incorporated by reference into this environmental analysis pursuant to CEQA Guidelines, §15150.

- Air Resources Board, *Supplement to June 2010 Staff Report on Proposed Actions to Further Reduce Diesel Particulate Matter at High-Priority California Railyards*, May 2011 (*Supplement to June 2010 Staff Report*). (http://www.arb.ca.gov/railyard/commitments/commitments.htm)
- Air Resources Board, *Board Resolution 10-29*, June 24, 2010. (http://www.arb.ca.gov/railyard/commitments/commitments.htm)
- Air Resources Board, *Proposed Actions to Further Reduce Diesel Particulate Matter at High Priority California Railyards*, June 2010 (*June 2010 Staff Report*). (http://www.arb.ca.gov/railyard/commitments/commitmentsarchive.htm)
- Air Resources Board, Presentation to Board "Update on Efforts to Reduce Emissions and Risks at High Risk Railyards," February 25, 2010. (http://www.arb.ca.gov/board/books/2010/022510/10-2-5pres.pdf)
- Air Resources Board, Presentation to Board "Staff Recommendations to Provide Further Locomotive and Railyard Emission Reductions," September 25, 2009. (http://www.arb.ca.gov/board/books/2009/092409/09-8-5pres.pdf)
- Air Resources Board, *Recommendations to Implement Further Locomotive and Railyard Emission Reductions*, September 2009 (*Recommendations Document*). (http://www.arb.ca.gov/railyard/ted/drftrec090909.pdf)
- Air Resources Board, *Technical Options to Achieve Additional Emissions and Risk Reductions from California Locomotives and Railyards*, August 2009 (*Technical Options Document*). (http://www.arb.ca.gov/railyard/ted/083109tedr.pdf)

- Air Resources Board, *ARB/Railroad Statewide Agreement, Particulate Emissions Reduction Program at California Rail Yards*, June 2005. http://www.arb.ca.gov/msprog/offroad/loco/loco.htm)
- Air Resources Board, *Memorandum of Mutual Understandings and Agreements, South Coast Locomotive Fleet Average Emission Program*, July 1998. http://www.arb.ca.gov/msprog/offroad/loco/loco.htm)

Railyard-specific health risk assessments, air dispersion modeling, and emission inventories are available at http://www.arb.ca.gov/railyard/hra/hra.htm.

BNSF San Bernardino:

- Air Resources Board, *Health Risk Assessment for the BNSF Railway San Bernardino Railyard*, June 2008.
- ENVIRON International, *Air Dispersion Modeling Assessment of Air Toxic Emissions from BNSF San Bernardino Railyard*, January 2007.
- ENVIRON International, *San Bernardino TAC Emissions Inventory*, January 2008.

BNSF Hobart:

- Air Resources Board, *Health Risk Assessment for the BNSF Railway Hobart Railyard*, November 2007.
- ENVIRON International, *Air Dispersion Modeling Assessment of Air Toxic Emissions from BNSF Hobart Railyard*, December 2006.
- ENVIRON International, *Los Angeles-Hobart Railyard TAC Emissions Inventory*, December 2006.

UP Commerce:

- Air Resources Board, *Health Risk Assessment for the Union Pacific Railroad Commerce Railyard*, November 2007.
- Sierra Research, *Toxic Air Contaminant* Emissions Inventory and Dispersion *Modeling Report for the Commerce Railyard, Los Angeles, California*, January 2007.

UP ICTF/Dolores:

- Air Resources Board, *Health Risk Assessment for the UP Intermodal Container Transfer Facility (ICTF) and Dolores Railyards*, April 2008.
- Sierra Research, *Toxic Air Contaminant Emissions Inventory and Dispersion Modeling Report for the Dolores and ICTF Railyards, Long Beach, California*, December 2007.

All documents incorporated by reference are either available at the website addresses noted below with certain documents, or at the California Air Resources Board, Stationary Source Division, 1001 "I" Street, Sacramento, CA.

II. PROJECT DESCRIPTION

A. Project Locations

The project covers four locations. A map of the region with the covered railyards and individual maps of each covered railyard are provided below.

Figure F-1
Four High-Priority Railyards Regional Map

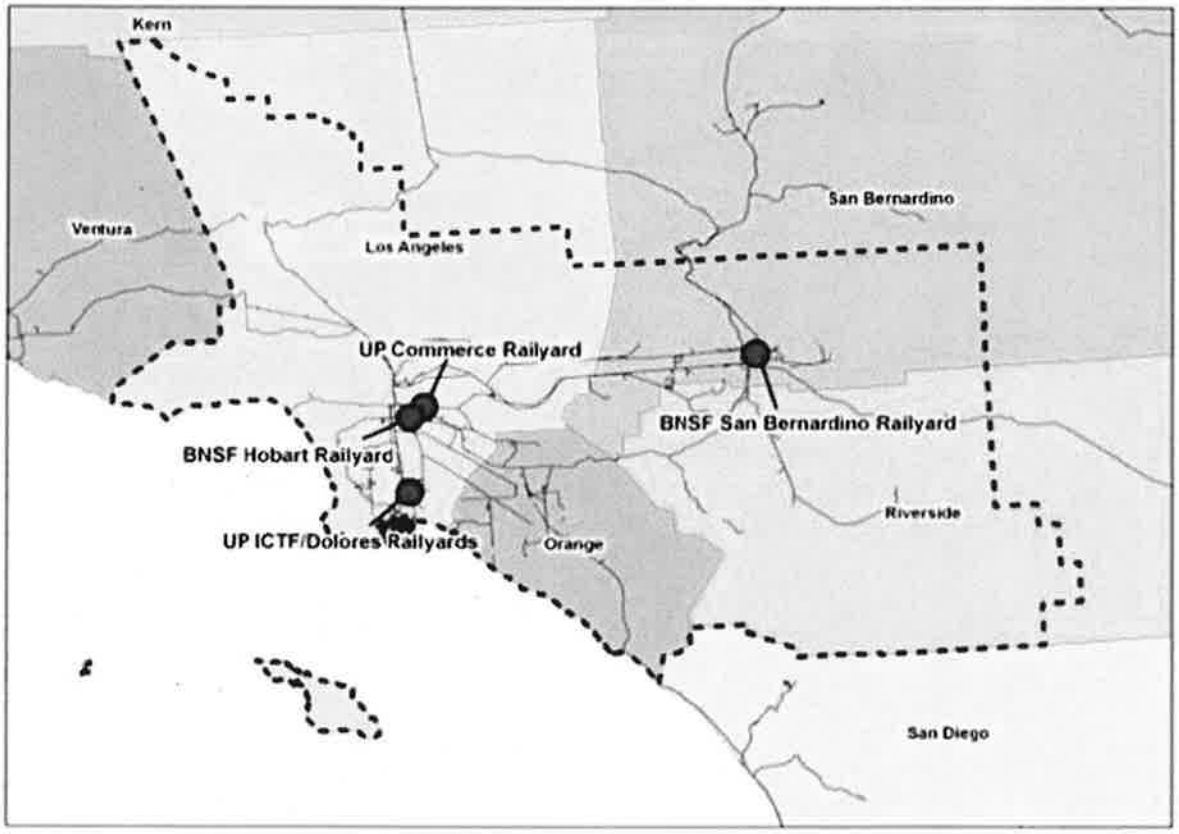


Figure F-2
BNSF San Bernardino Railyard
1535 West Fourth Street
San Bernardino, CA 94211

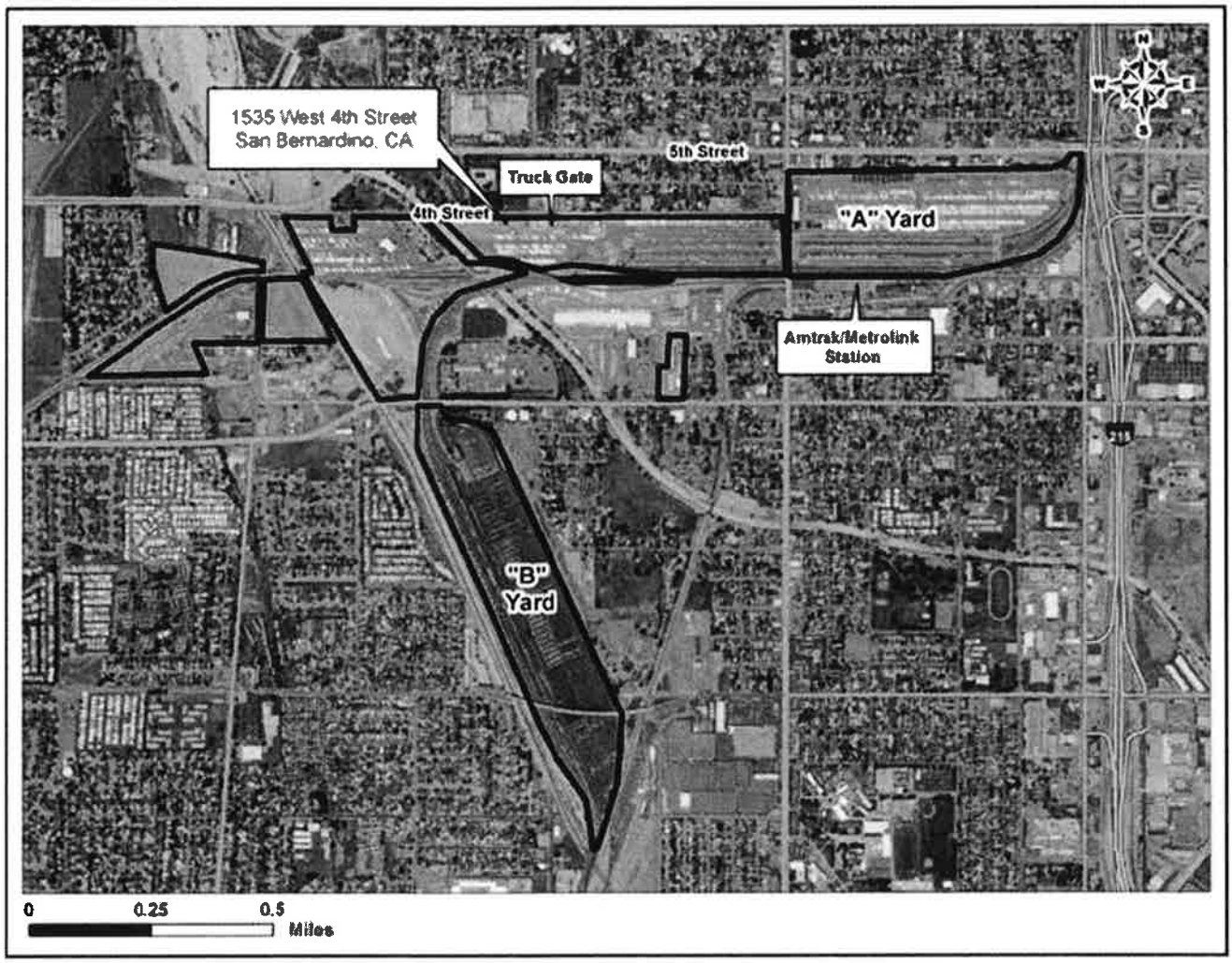


Figure F-3
BNSF Hobart Railyard
3770 East Washington Boulevard
Commerce, CA 90023

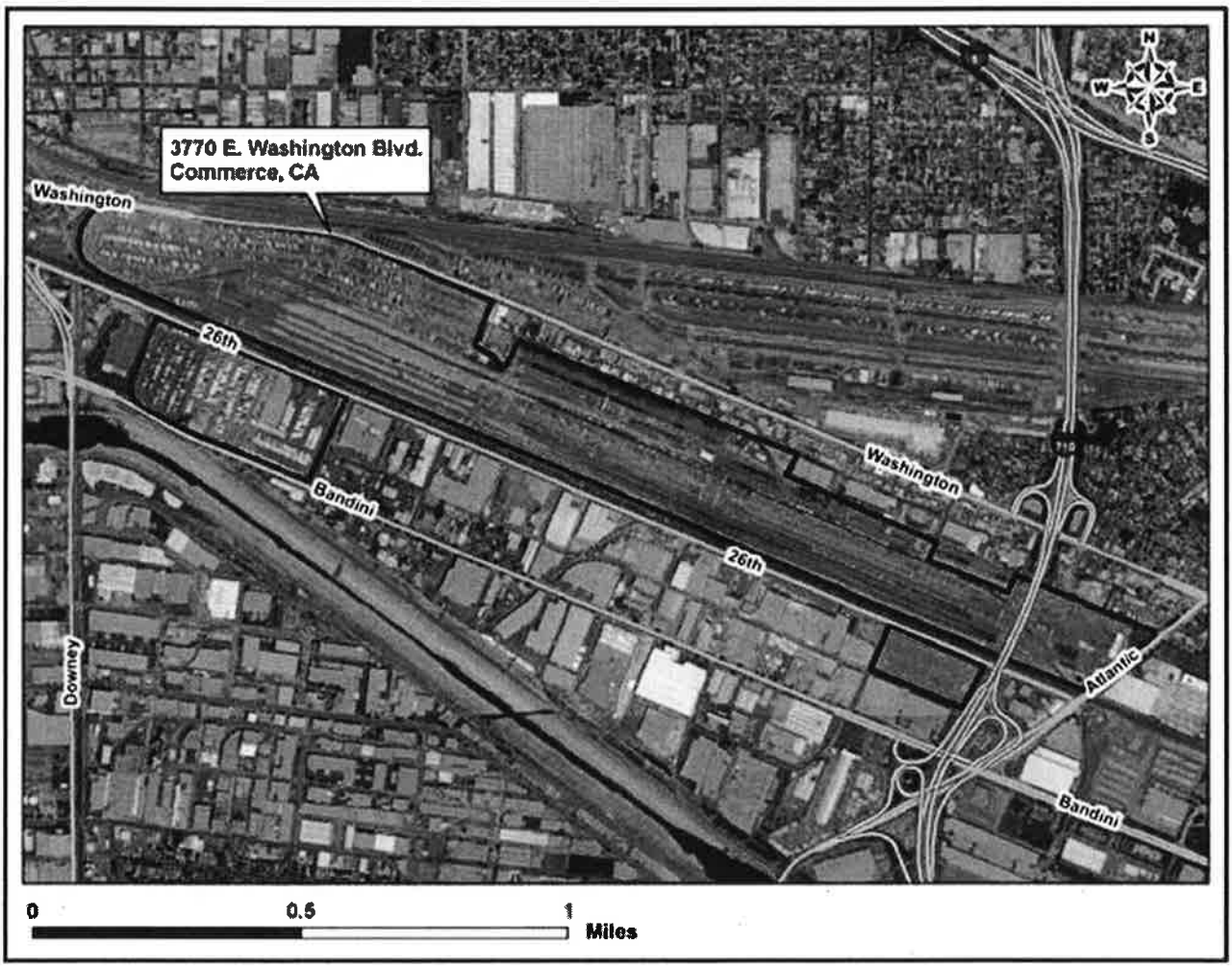


Figure F-4
UP Commerce Railyard
4341 East Washington Boulevard
Commerce, CA 90023

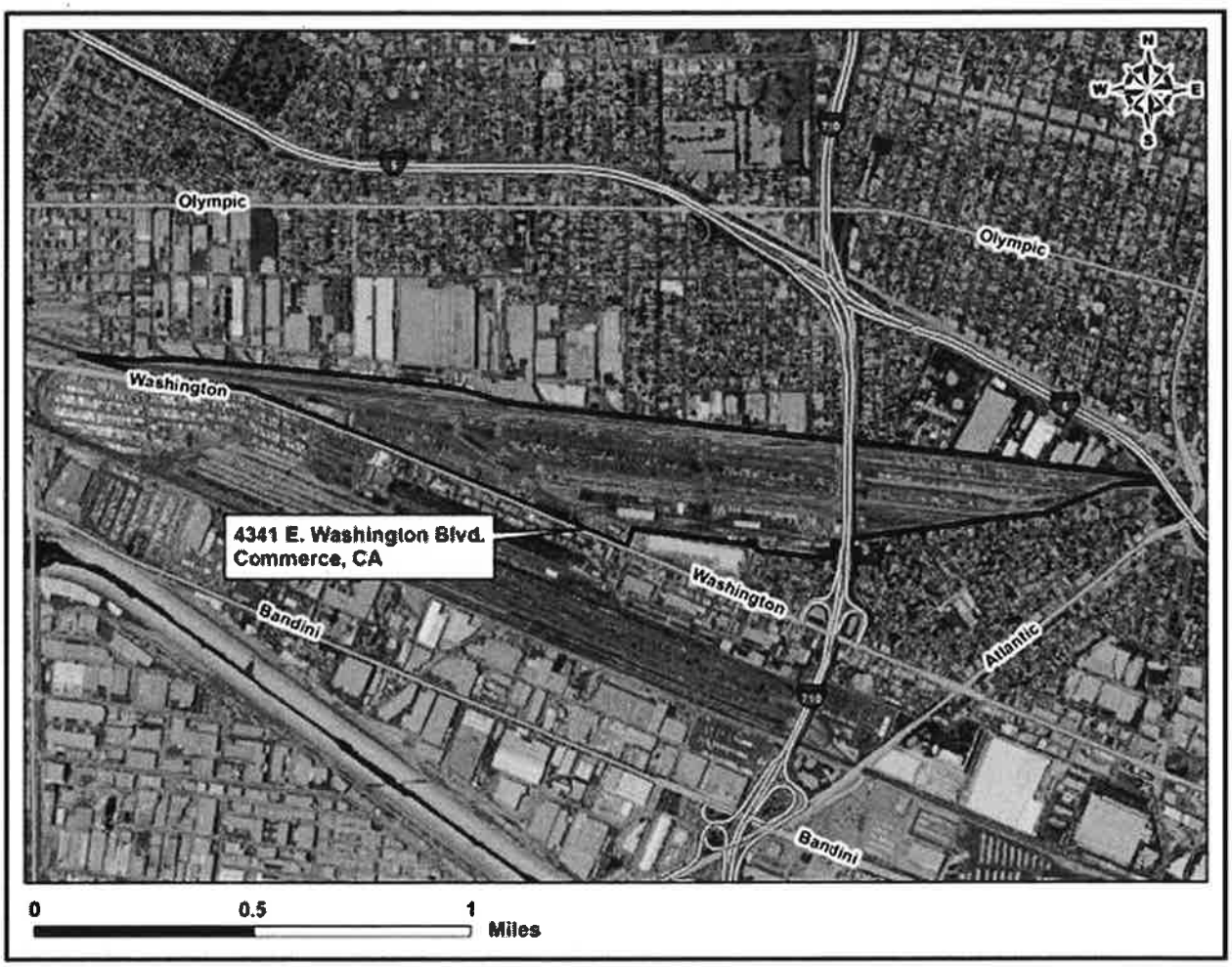
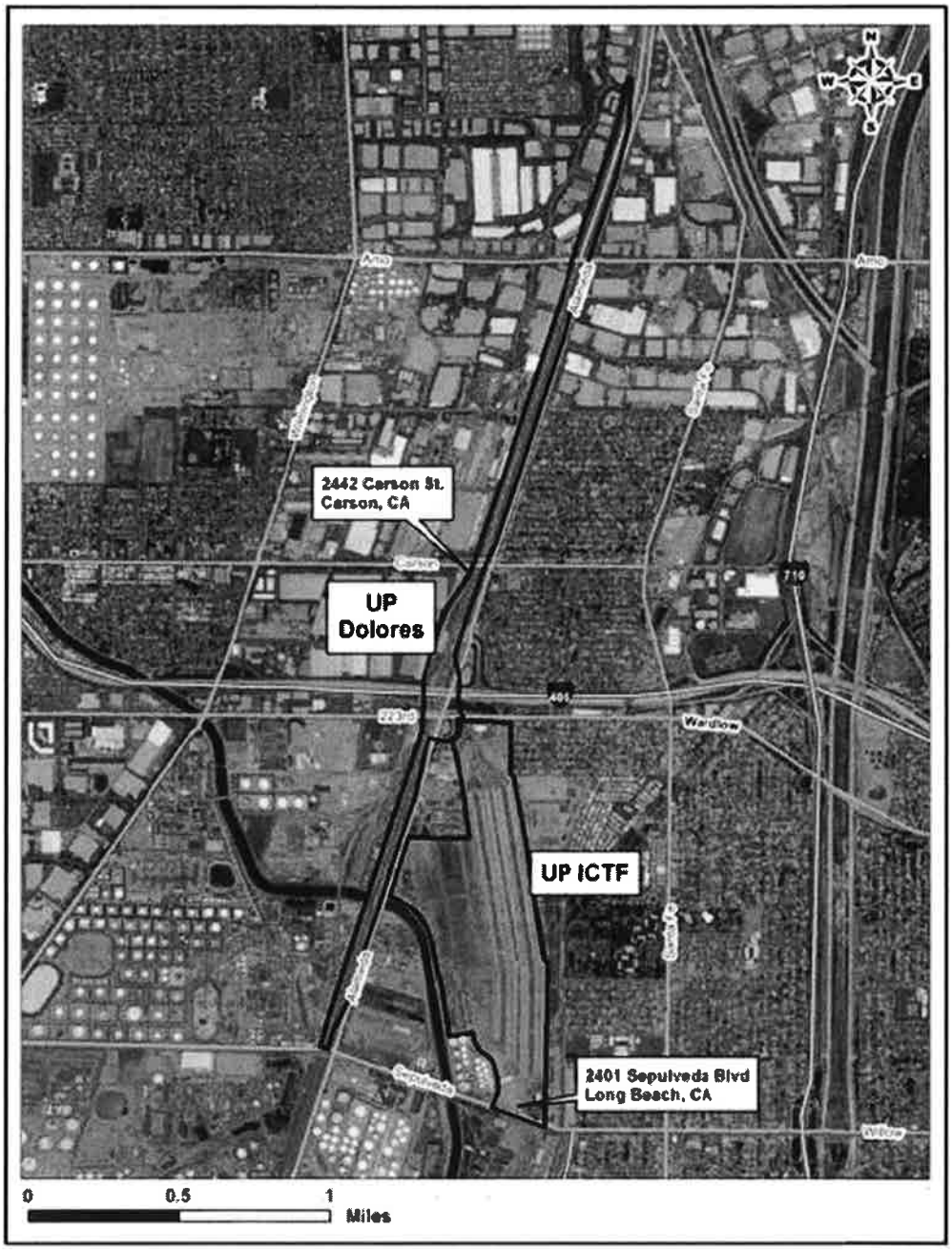


Figure F-5
UP ICTF/Dolores Railyards

Intermodal Container Transfer Facility:
2401 East Sepulveda Boulevard
Long Beach, CA 90810

Dolores Railyard
2442 East Carson Street
Carson, CA 90810

These facilities are treated as one combined railyard.



B. Project Objectives

The primary project objective is to reduce air emissions of diesel particulate matter (PM) from operations at the four identified high-priority railyards, beyond the levels expected under the existing program of adopted regulations and agreements (described below), and specifically to achieve at least an 85 percent reduction in diesel PM emissions at each railyard between 2005 and 2020, regardless of growth in activity or operations. Of the 18 major railyards in California analyzed by ARB staff, these four railyards posed the greatest estimated excess cancer risk to residents of surrounding communities in 2005. The driver for this cancer risk is exposure to diesel PM emissions, which ARB has identified as a toxic air contaminant (TAC).[8]

Supporting objectives include the ability to monitor compliance, ensure that railroads do not reassign the oldest locomotives from these four railyards to other California railyards, and define ARB actions if the railroads fail to comply.

C. Project Description

1. Overview

The proposed project is ARB approval and implementation of a set of voluntary, but binding agreements (called the Revised 2010 Commitments) between ARB and BNSF and UP railroad companies that would require the railroads to achieve substantial defined reductions in diesel PM emissions at four high-priority railyards over a ten-year period, and to do other specified actions. The four railyards are BNSF San Bernardino and Hobart Railyards, and the UP Commerce and ICTF/Dolores Railyards.

The Revised 2010 Commitments are the result of a stated desire by both ARB and the railroad companies to achieve diesel PM reductions at the railyards in a measurable, reliable, and cost-effective manner. The reductions go well beyond levels that are possible under ARB's regulatory framework alone.

Under the Revised 2010 Commitments, the railroads would target their financial resources to making the greatest air quality improvements at the railyards that posed the greatest public health risk to their neighbors according to ARB's assessment of 2005 operations. Implementation would provide additional benefits throughout the South Coast Air Basin and statewide as cleaner locomotives travel beyond the four high-priority railyards.

Staff is proposing these voluntary agreements because they are the most effective and most certain way to achieve substantial new emission reductions from the locomotives that ARB cannot regulate. ARB has already regulated the railyard sources under its

[8] Title 17, California Code of Regulations, §93000.

direct authority, including drayage trucks,[9] cargo handling equipment,[10] transport refrigeration units,[11] and diesel fuel.[12] However, ARB lacks authority to regulate the emissions of late-model or remanufactured locomotives that contribute the majority of railyard emissions in future years. Under the federal Clean Air Act, ARB can regulate only the oldest locomotives, which no longer regularly operate in these four high-priority railyards.[13]

Although participation by the railroads in the Revised 2010 Commitments is voluntary, once executed, the Revised 2010 Commitments become binding on all parties. The emission reductions must be achieved within specific timeframes. There are recordkeeping, reporting, and compliance monitoring provisions associated with the project. These include ongoing technical reviews of emissions data, staff surveys of locomotive activity, railyard inspections, field surveys, and specified ARB actions if the Revised 2010 Commitments are not met. If approved, the Revised 2010 Commitments represent the region's best opportunity to significantly reduce railyard emissions and health risk at a rate above and beyond what would otherwise occur over the next ten years.

The June 15, 2010 report entitled *Proposed Actions to Further Reduce Diesel Particulate Matter at High Priority California Railyards* (*June 2010 Staff Report*) provides extensive information on the basis, origin and development of the Revised 2010 Commitments. (See *Documents Incorporated by Reference* in Chapter I.)

2. Key Provisions

The provisions of the Revised 2010 Commitments for each high-priority railyard include:

- A performance standard that sets a declining cap on the diesel PM emissions at each railyard from 2011-2020 that will cut diesel PM by at least 85 percent between 2005 and 2020, regardless of growth in cargo activity or operations.
- Independent ARB verification of railroad compliance with the required emission reduction levels.

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[9] Title 13, California Code of Regulations, §2027. New section filed November 24, 2008, operative December 24, 2008.
[10] Title 13, California Code of Regulations, §2479. New section filed and operative December 1, 2006.
[11] Title 13, California Code of Regulations, §2477. New article and section filed November 10, 2004, operative December 10, 2004.
[12] Title 13, California Code of Regulations, §2282-2285. Amendment filed July 15, 2004, operative August 14, 2004.
[13] U.S. EPA establishes emission standards for locomotives. The Board would have the authority to establish regulations for locomotives that primarily operate in California and that were manufactured prior to 1973 or that exceed 133 percent of their useful life since original manufacture or last remanufacture, whichever is later. (A detailed discussion of ARB's regulatory authority is in Appendix A of the *Recommendations to Implement Further Locomotive and Railyard Emission Reductions*, September 2009. http://www.arb.ca.gov/railyard/ted/drftrec090909.pdf)

- A process for review of any final determination by ARB that a railroad has failed to comply, as well as a clear trigger for ARB regulatory action if an administrative appeals panel upholds this determination.
- Periodic emission inventories, health risk assessments, and emission reduction plans for each railyard.
- Railroad evaluation of specific potential operational changes to reduce emissions and/or health risk.
- A prohibition on the railroads on re-assigning any of the very oldest locomotives that might operate at the four high-priority railyards to other railyards in California.
- A joint ARB/railroad demonstration program for advanced locomotive engines or add-on pollution control (aftertreatment) devices to reduce emissions within a railyard.
- Requirements for ARB to make publicly available documents related to implementation and a process for ongoing public participation for the duration of the project.
- A legal mechanism for residents of neighborhoods near the four railyards to ensure ARB meets its obligations by bringing action against ARB in State court following a defined process.
- Defined conditions under which railroads could withdraw from the Revised 2010 Commitments.
- A backstop requirement to ensure that if the railroads should elect to withdraw, the railroads must maintain the emission reduction progress achieved as of the last compliance milestone through 2020.

3. Emission Reduction Obligations

Table F-1 summarizes the diesel PM emission reduction levels for each railyard, which indicate the percent reduction from baseline emissions in 2005 that must be achieved by the calendar year indicated. These emission reduction levels reflect the benefits of both the existing program (adopted regulations and agreements) and the new actions railroads would take under the Revised 2010 Commitments. The Revised 2010 Commitments set a hard cap on railyard emissions in each milestone year, independent of the growth in container traffic or railyard activity.

Table F-1
Proposed Diesel PM Emission Reduction Levels and Schedules

Railyard	Percent Emission Reductions from 2005 Baseline by December 31st Compliance Date				
	2011	2013	2015	2017	2020
BNSF San Bernardino	45	50	68	73	85
BNSF Hobart	55	65	76	78	85
UP Commerce	50	55	69	70	85
UP ICTF/Dolores	60	65	74	75	85

4. Preparation and Submittal of Documents

The Revised 2010 Commitments require the railroads to prepare and submit multiple diesel PM emission inventories, air dispersion modeling, and emission reduction plans specific to each railyard. They also require ARB to use the inventories and dispersion modeling to provide updated estimates of the health risk associated with diesel PM from railyard operations. ARB will make all of these documents available to the public via its website. The Revised 2010 Commitments include a detailed annual schedule for submittal and posting of each document required in that calendar year.

5. Evaluation of Operational Changes

During the public process, community members expressed interest in ensuring that the railroads consider operational changes that could reduce emissions and/or health impacts from rail operations on nearby residents. These changes may reduce risk through direct emission reductions from specific sources, increasing the distance between the emission sources and nearby residents, or both.

As a result, the Revised 2010 Commitments include requirements that the railroads evaluate various railyard-specific operational changes, and make recommendations as to the appropriateness of implementing those changes. As part of the operational review, the railroads will consider potential diesel PM emission reductions, technical feasibility, operational and safety impacts on the railyards, availability of land access, costs and cost-effectiveness of such actions, and any other railyard-specific factors.

Examples of operational changes include the relocation of truck gates, installation and operation of electric infrastructure to support rail-mounted gantry cranes and stationary transport refrigeration units, relocation of yard tractor and transport refrigeration unit operation, relocation of locomotive maintenance and service facilities, and installation of stationary collection systems to reduce locomotive maintenance and service-related

emissions. The Revised 2010 Commitments include deadlines for the railroads to complete their evaluations of specific operational changes at each railyard and a requirement for ARB to post those evaluations on the website.

The Revised 2010 Commitments would not increase the level of cargo activity or operations at the railyards – the level of activity is governed by economic conditions and the amount of cargo that the railroads' customers chose to move via their lines. However, some of the potential operational changes triggered by the Revised 2010 Commitments could shift the existing noise, light, or transportation or traffic impacts of current railyard activities from one set of nearby residents to another set of residents if operations are relocated within the railyard. These potential changes are evaluated in the Impact Analysis chapter.

6. ARB Action if Railroads Fail to Comply

The Revised 2010 Commitments define a process that ARB will use to assess the railroads' compliance with the emissions performance targets and other railroad responsibilities. There are also dispute resolution procedures that include an administrative appeals panel. The panel for a dispute specific to a railyard includes a representative from the railroad operating that railyard, a representative from ARB, and a presiding third member from a list jointly developed by the railroad and ARB. The railroad and ARB representatives have an advisory role; the presiding third panel member is the sole decision maker to resolve disputes. Meetings of the panel and any evidence submitted by the railroad, ARB, and any other interested parties are public, except for any precautions necessary to preserve the confidentiality of trade secret or other confidential information.

Upon a final determination of non-compliance by ARB's Executive Officer (or, if appealed by the railroad, the administrative appeals panel), ARB will submit to the Board the following locomotive and railyard rulemakings:

- A regulation of switch and medium horsepower locomotives that are not preempted under federal law (e.g., locomotives that primarily operate in California and that were manufactured prior to 1973 or that exceed 133 percent of their useful life since original manufacture or last remanufacture, whichever is later).
- A designated railyard regulation that requires risk reduction audits and plans to achieve targeted emission reduction levels.

ARB will also consider the following actions:

- Pursue federal legislation to expand ARB authority to adopt regulations for in-use locomotives.
- Petition the U.S. Environmental Protection Agency (U.S. EPA) to strengthen existing federal locomotive regulations.

7. Further Information

The full text of the Revised 2010 Commitments for each railyard is provided in Appendices B-E of this *Supplement to the June 2010 Staff Report*, to which this FED is also appended. The documents incorporated by reference into this FED provide the history of why and how the Revised 2010 Commitments were developed. If the Revised 2010 Commitments are approved, ARB will transmit them to each railroad for concurrence and execution. Actions then can begin immediately and the 2011 emission reduction targets are effective.

III. ENVIRONMENTAL SETTING

A. Existing Environment

The four high-priority railyards – BNSF San Bernardino, BNSF Hobart, UP Commerce, and UP ICTF/Dolores – are existing intermodal facilities currently operating at the identified locations within the South Coast Air Basin, which continues to experience some of the most severe air pollution in the U.S. The two UP railyards also have locomotive refueling, maintenance, and switch locomotive operations.
Below is detailed discussion about the location and primary operations at each railyard.

1. BNSF San Bernardino Railyard

The BNSF San Bernardino Railyard is located at 1535 West 4th Street in San Bernardino, California, and encompasses about 168 acres.[14] The Atchison, Topeka & Santa Fe Railroad (ATSF) San Bernardino Railyard was originally opened in November of 1885, to serve as a key ATSF terminal and locomotive maintenance facility between Kansas City and Los Angeles. The ATSF San Bernardino terminal linked with the Barstow terminal upon the completion of rail track over the Cajon Pass in 1885.[15] ATSF began formal intermodal operations at the San Bernardino Railyard in 1986,[16] and became part of BNSF Railway when ATSF merged with Burlington Northern Railroad in the mid-1990's.[17]

The BNSF San Bernardino Railyard is located in an area primarily zoned for commercial and manufacturing activities. However, several residential areas surround the facility, some of them within 100 feet. The railyard is divided into two distinct sections referred to as the "A" yard and the "B" yard. The "A" yard, aligned in an east - west direction, is bordered along the north side by West 4th and West 5th street, and along the south side by West 3rd Street and an adjacent main line. The "B" yard is aligned roughly in a north-south direction, and is bordered along the west side by North 8th Street. Additionally, several residential properties border the BNSF San Bernardino Railyard on the north and west side and along the south and east side of the "A" yard and the "B" yard.[18]

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[14] Air Resources Board, *Health Risk Assessment for the BNSF Railway San Bernardino Railyard*, June 2008, p. 5.
[15] http://en.wikipedia.org/wiki/California_Southern_Railroad. Web archive, March 16, 2011.
[16] Economics & Politics, Inc., *Hemet: Demographic, Economic & Quality of Life Data*, September 2005, p. 50.
[17] http://en.wikipedia.org/wiki/Atchison,_Topeka_and_Santa_Fe_Railway. Web archive, March 16, 2011.
[18] Air Resources Board, *Health Risk Assessment for the BNSF Railway San Bernardino Railyard*, June 2008, p. 5.

2. BNSF Hobart Railyard

The BNSF Hobart Railyard is located at 3770 East Washington Boulevard in Commerce, California, approximately 4 miles southeast of downtown Los Angeles.[19] BNSF Hobart Railyard is referenced as the beginning point of a mainline between Hobart and Riverside Junction built by the San Pedro Los Angeles and Salt Lake Railroad in 1901.[20] Intermodal operations began in 1952 on two dedicated tracks.[21] Atchison, Topeka & Santa Fe (ATSF) subsequently merged with BNSF Railway in the mid-1990's.[22]

BNSF Hobart Railyard is located in an area primarily zoned for commercial and manufacturing activities, but has several residential areas located within one mile. The BNSF Hobart Railyard encompasses approximately 243 acres, bordered by East Washington Boulevard and Sheila Street to the north, South Atlantic Boulevard to the east, the adjacent main line and East 26th Street to the south, and South Downey Road to the west. The eastern end of the BNSF Hobart Railyard is bisected by the I-710 freeway. BNSF Hobart Railyard is also located within three miles of five other major roadways, including: I-5 and Highway 60 to the north, I-110 to the west, and I-10 and Highway 101 to the northwest. The UP Commerce Railyard is located to the north of the BNSF Hobart Railyard on the other side of East Washington Boulevard.[23]

The BNSF Hobart Railyard generally runs from the northwest to the southeast and consists of a locomotive classification yard, intermodal areas, and administration and equipment maintenance buildings. The railyard also includes two satellite areas used for container storage and located across East 26th Street at the southwest and southeast ends of the railyard.[24] BNSF Hobart Railyard is supported by the small BNSF Commerce-Eastern domestic container intermodal railyard and the BNSF Sheila Mechanical facility (i.e., locomotive refueling and maintenance), which are both located about 1 to 2 miles east of BNSF Hobart Railyard.[25,26,27]

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[19] Air Resources Board, *Health Risk Assessment for the BNSF Railway Hobart Railyard*, November 2007, p. 6.
[20] http://en.wikipedia.org/wiki/San_Pedro,_Los_Angeles_and_Salt_Lake_Railroad. Web archive, March 16, 2011.
[21] BNSF Railway, *Los Angeles (Hobart) and Commerce BNSF Intermodal Facilities*. Informational brochure provided by BNSF to ARB, May 2010.
[22] http://en.wikipedia.org/wiki/Atchison,_Topeka_and_Santa_Fe_Railway. Web archive, March 16, 2011.
[23] Air Resources Board, *Health Risk Assessment for the BNSF Railway Hobart Railyard*, November 2007, p. 6.
[24] Air Resources Board, *Health Risk Assessment for the BNSF Railway Hobart Railyard*, November 2007, p. 6.
[25] Air Resources Board, *Health Risk Assessment for the BNSF Railway Sheila Mechanical Railyard*, November, 2007, pp. 6-7.
[26] Air Resources Board, *Health Risk Assessment for the BNSF Commerce Eastern Railyard*, November, 2007, p. 1.
[27] ENVIRON International, *Commerce-Eastern Railyard TAC Emissions Inventory*, December 2006, p. 3-1.

3. UP Commerce Railyard

The UP Commerce Railyard is located at 4341 East Washington Boulevard, Commerce, California, approximately 4 miles southeast of downtown Los Angeles.[28] The UP Commerce Railyard was originally built by the Los Angeles and Salt Lake Railroad as the "East Yard" in 1924. In the early 1990's, UP removed the classification hump, and limited train building to flat switching, to transition more of the yard operations to intermodal.[29]

The UP Commerce Railyard runs directly parallel (for about a mile) and across Washington Boulevard from the BNSF Hobart Railyard. The UP Commerce Railyard covers a triangular area surrounded by both residential and commercial properties, as well as several major freeways. An overpass for the I-710 freeway bisects the UP Commerce Railyard. To the south side of the railyard (on both sides of the I-710 overpass), residences are located between the railyard fence line and Washington Boulevard. Bandini Elementary School is also located in this area, east of the I-710. The north side of the UP Commerce Railyard is surrounded by commercial properties and residential housing. Residential properties are located north of the railyard on both sides of the I-710 freeway overpass, approximately 200 feet from the railyard.[30]

Facilities within the railyard include: classification tracks, a gate complex for inbound and outbound intermodal truck traffic, intermodal loading and unloading tracks, a locomotive service track, a locomotive maintenance shop, a freight car repair shop, an on-site wastewater treatment plant, and various buildings and facilities supporting railroad and contractor operations.[31]

4. UP ICTF/Dolores Railyards

The UP ICTF/Dolores Railyards are located in Long Beach and Carson, California, about 4 miles north of the Port of Long Beach.[32] The UP ICTF intermodal railyard, a near dock facility leased from the San Pedro Ports, was opened in 1986. The Dolores Railyard was built during World War II (1943) by Pacific Electric Railroad to accommodate growing movements and storage of war-related freight traffic to and from the San Pedro harbor.[33]

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[28] Air Resources Board, *Health Risk Assessment for the Union Pacific Railroad Commerce Railyard*, November 2007, p. 6.
[29] Solomon, Brian, *Union Pacific Railroad*, 2000, pp. 69-70.
[30] Air Resources Board, *Health Risk Assessment for the Union Pacific Railroad Commerce Railyard*, November 2007, p. 6.
[31] Air Resources Board, *Health Risk Assessment for the Union Pacific Railroad Commerce Railyard*, November 2007, p. 6.
[32] Air Resources Board, *Health Risk Assessment for the UP Intermodal Container Transfer Facility (ICTF) and Dolores Railyards*, April 2008, p. 6.
[33] http://www.erha.org/pesspd.htm. Web archive, March 16, 2011.

The UP ICTF/Dolores facility has two railyards, (1) the ICTF intermodal yard to the east, and (2) Dolores flat switching and servicing yard to the northwest. ICTF covers a narrow area between East Sepulveda Boulevard and East 233rd Street, just south of the I-405 freeway. The main portion of the Dolores Yard covers a narrow area approximately one-half mile in length along the Alameda Corridor, connected to ICTF with a series of parallel tracks approximately 1.4 miles long on the north end and 0.9 miles long on the south end.[34]

The general land uses on the west, south, and north sides of the facility are commercial and industrial. There are three major refineries located within about one mile of the railyard boundaries: BP Carson Refinery, ConocoPhillips Refinery, and Shell Refinery (purchased by Tesoro in 2007). A number of industrial storage facilities are located to the southwest. An overpass of the I-405 freeway passes over the south end of the Dolores Yard. Between the eastside of the facility and the I-710 freeway (approximately one mile from the facility boundary) is a residential area. The nearest residences are approximately 100 to 400 feet from the eastern boundary of both railyards.[35]

5. Existing Air Quality

At these four high-priority railyards, UP and BNSF process shipments of international and/or domestic freight that may be transported by ship, locomotive, and/or truck to destinations within or outside California. The railroads rely primarily on diesel-powered engines in locomotives, trucks, and cargo handling equipment at the railyards to transfer and transport the freight. These sources emit diesel PM, oxides of nitrogen (NOx), sulfur oxides (SOx), hydrocarbons (HC) or volatile organic compounds (VOC), greenhouse gases and other climate change contributors. The NOx and HC emissions combine in the atmosphere in the presence of sunlight to form high regional levels of ozone, while the diesel PM, NOx, SOx, and HC emissions also contribute to high regional levels of fine particulate matter that is 2.5 microns or less in diameter (PM2.5).

All four railyards are located in the South Coast Air Basin. The South Coast Air Basin is the nation's second largest urban area and California's largest metropolitan region. It includes the southern two-thirds of Los Angeles County, all of Orange County, and the western, urbanized portions of Riverside and San Bernardino counties. The South Coast Air Basin is home to 16 million people, about 40 percent of the State's population. The South Coast Air Basin is also home to over 10 million vehicles.

[34] Air Resources Board, *Health Risk Assessment for the UP Intermodal Container Transfer Facility (ICTF) and Dolores Railyards*, April 2008, p. 6.
[35] Air Resources Board, *Health Risk Assessment for the UP Intermodal Container Transfer Facility (ICTF) and Dolores Railyards*, April 2008, p. 6.

a. Regional Air Pollution

Some of the nation's highest concentrations of PM2.5 and ozone occur in the South Coast Air Basin despite decades of increasingly stringent air pollution controls. The South Coast Air Basin is one of two federal PM2.5 non-attainment areas in the State, and the most serious in the nation. Its ozone levels are currently 50 percent above the federal standard, making it the nation's worst ozone area. The Basin also violates the State's ambient air quality standards for ozone, PM2.5, PM10, and nitrogen dioxide; a few areas of the Basin violate the State's ambient air quality standard for lead.[36]

b. Air Toxics and Cancer Risk

The directly emitted diesel PM contributes to an increased localized risk of cancer and non-cancer effects, including premature death, cardiac disease, and respiratory illnesses like asthma and bronchitis. Based on air quality monitoring from 2004-2006, the South Coast Air Quality Management District estimated that the carcinogenic risk from air toxics in the basin is about 1,200 chances per million, with diesel exhaust accounting on average for about 84 percent of the total.[37] The increased risk of cancer is based on constant exposure to diesel PM over a 70-year lifetime, the standard methodology for estimating cancer risk from air toxics. With the same exposure assumptions, the maximum excess cancer risk in the most impacted neighborhoods from operations at the four high-priority railyards ranges from 500 to 2,500 in a million for calendar year 2005, decreasing to 180 to 650 in a million for calendar year 2010.

B. Regulatory Setting

1. Regulations

a. Federal Standards for Locomotive Emissions

Under the Clean Air Act, U.S. EPA has the sole authority to regulate emissions from newly manufactured, as well as remanufactured locomotives and locomotive engines. Federal standards have been adopted by the U.S. EPA in two regulatory actions:[38]

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[36] Air Resources Board, 2010 Area Designations, http://www.arb.ca.gov/desig/adm/adm.htm. Web archive, May 5, 2011

[37] South Coast Air Quality Management District, *MATES-III - Final Report Multiple Air Toxics Exposure Study in the South Coast Air Basin*, September 2008, Executive Summary.

[38] ARB's authority to directly regulate locomotives is limited. To determine the extent of the ARB's authority to adopt emission standards for railyard sources, including locomotives, one must carefully consider ARB's authority in relation to the authority granted to ARB under the Health and Safety Code and the CAA and the constraints imposed by the preemptions of state regulation under the CAA and the Interstate Commerce Commission Termination Act of 1995 (ICCTA). A more detailed discussion of ARB's authority over locomotives is set forth in Appendix A of the Air Resources Board's *Recommendations Document* and at Chapter VI, Section D.1., *infra.*

- *Tier 0-2 standards:* The first emission regulations for locomotives were adopted on December 17, 1997.[39] The rulemaking, which became effective in 2000, applies to locomotives originally manufactured since 2000, and is also applicable to 1973-1999 model year locomotives any time they are remanufactured. Tier 0-2 standards have been met through engine design methods, without the use of aftertreatment (emission controls – like a diesel PM filter – that capture the engine exhaust and reduce the air pollutants before releasing it to the atmosphere).
- *Tier 3-4 standards:* A regulation signed on March 14, 2008 introduced more stringent emission requirements. Tier 3 standards will be met by engine design methods and will become effective in 2011 and 2012. Tier 4 standards will become effective in 2015. Locomotive manufacturers may need to incorporate aftertreatment technologies to meet the Tier 4 standards, but the standard does not require aftertreatment. The 2008 regulation also includes more stringent emission standards for remanufactured Tier 0-2 locomotives.[40]

Table F-2 below shows the level of stringency of each established U.S. EPA locomotive emission standard in grams of pollutant per brake horsepower-hour (g/bhp-hr) and the associated percent reduction compared to uncontrolled, pre-Tier 0 emission levels, for NOx, PM, and HC.[41] The standards and test procedures are different for the two primary types of locomotives – the smaller switch locomotives that are typically assigned to a specific railyard to move railcars around to assemble trains, and the larger, more powerful line haul locomotives that move entire trains longer distances. ARB also refers to a third type of locomotive – a medium horsepower locomotive – that applies primarily to former older interstate line haul locomotives that were cascaded down from national to regional or local service to perform as train helpers over mountains, short haulers, or in some cases as yard switch locomotives. These medium horsepower locomotives are subject to the line haul emission standards shown below.

[39] Federal Register, Volume 63, Number 73, pp. 18997-19084, April 16, 1998.
[40] Federal Register, Volume 73, Number 126, pp. 37095-37144, June 30, 2008.
[41] Title 40, Code of Federal Regulations, Part 1033.101, a.

Table F-2
Federal Locomotive Emission Standards and Percent Control[42,43]

Line Haul Locomotives							
Emission Tier	Year of Manufacture	NOx		PM		HC	
		Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control
Pre-Tier 0	1973-1999	13.5*	n/a	0.6**	n/a	1.0	n/a
Tier 0	2000-2001	9.5	30	0.6	0	1.0	0
Tier 1	2002-2004	7.4	45	0.45	25	0.55	45
Tier 2	2005-2011	5.5	59	0.2	67	0.3	70
Tier 3	2012-2014	5.5	59	0.1	83	0.3	70
Tier 4	2015	1.3	90	0.03	95	0.14	86
Switch Locomotives							
Emission Tier	Year of Manufacture	NOx		PM		HC	
		Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control	Standard (g/bhp-hr)	Percent Control
Pre-Tier 0	1973-1999	17.4*	n/a	0.72**	n/a	2.1	n/a
Tier 0	2000-2001	14.0	20	0.72	0	2.1	0
Tier 1	2002-2004	11.0	37	0.54	25	1.2	43
Tier 2	2005-2011	8.1	53	0.24	67	0.6	71
Tier 3	2012-2014	5.0	71	0.1	86	0.6	71
Tier 4	2015	1.3	93	0.03	96	0.14	93

* U.S. EPA Locomotive Emissions Standards – Regulatory Support Document – p. 96 – Estimated NOx Emission Rates.
** ARB staff assumed older pre-Tier 0 line haul and switch locomotives would be able to emit up to the Tier 0 PM emission standards, based on American Association of Railroads in-use emission testing (required to comply with U.S. EPA in-use emission testing requirements)for older switch locomotives with EMD 645 engines.

The 2008 U.S. EPA rule will cut locomotive PM and NOx emissions by as much as 90 percent from uncontrolled levels when fully implemented, reducing annual emissions of NOx by about 800,000 tons and PM emissions by 27,000 tons. These emission reductions will continue to grow beyond 2030 as fleet turnover is completed. U.S. EPA estimates that national locomotive fleet turnover can take up to 30 years or more.[44]

[42] Title 40, Code of Federal Regulations, Part 1033.101, a.
[43] U.S. EPA Fact Sheet EPA-420-F-09-025, April 2009.
[44] U.S. EPA, *Regulatory Announcement: EPA Finalizes More Stringent Emissions Standards for Locomotives and Marine Compression-Ignition Engines*, EPA420-F-08-004, March 2008, p. 4.

b. California Authority to Regulate Locomotive Emissions

To determine the extent of the ARB's authority to adopt emission standards for railyard sources, including locomotives, one must carefully consider ARB's authority in relation to the authority granted to ARB under the Health and Safety Code and the CAA and the constraints imposed by the preemptions of State regulation under the CAA and the Interstate Commerce Commission Termination Act of 1995 (ICCTA). These are summarized briefly below, and discussed in detail in Appendix A of the *Recommendations Document*.[45]

To the extent that ARB has authority under the CAA to adopt emission standards for locomotives manufactured prior to 1973, and non-new locomotives that have exceeded 133 percent of their useful lives, that authority must be harmonized with the purposes and intent of the ICCTA preemption. Harmonization involves a factual inquiry. Based on the facts and rationale summarized below, ARB staff believes that ARB likely possesses authority to establish emission standards for pre-2000 model-year switch and medium horsepower locomotives, that have not been subsequently remanufactured to meet U.S. EPA emissions standards, and that principally operate in intrastate service. On balance, given the strong federal directives under the CAA to achieve attainment of national ambient air quality standards (NAAQS) and the express authority given to California to regulate non-preempted locomotives, the limited regulation of such intrastate locomotives would seem to outweigh any potential undue impairment to railroad operations.

ARB has authority under the CAA to adopt standards for all CAA non-preempted locomotives. To the extent that switch and medium horsepower locomotives are not preempted under the CAA, ARB has authority under California law to adopt emission standards for these in-use locomotives, but must receive authorization from U.S. EPA pursuant to CAA Section 209 (c)(2). Additionally, such regulations must be harmonized with the purposes and intent of the ICCTA preemption.[46] Whether these locomotives are preempted under ICCTA is a factual question.

In contrast to intrastate switch and medium horsepower locomotives, locomotives that are engaged in line haul interstate operations may be preempted under the CAA in that they were likely manufactured on or after 1973 and are within 133 percent of their useful lives since initial manufacture or subsequent remanufacture. To the extent that they are not preempted under the CAA, it could be argued that the interstate nature of these

[45] Air Resources Board, *Recommendations to Implement Further Locomotive and Railyard Emission Reductions*, September 2009. (http://www.arb.ca.gov/railyard/ted/drftrec090909.pdf)

[46] See *Association of American Railroads (AAR) v. the South Coast Air Quality Management District* (9th Cir. 2010) 622 F.3d 1094, 1098; See also *New York Susquehanna & Western Railway Corporation v. Jackson (Jackson)* 500 F.3d 238, 253.

locomotives makes adoption of State emission standards unduly burdensome to railroad operations and, therefore, preempted under ICCTA.

In summary, ARB staff recognizes that its authority to regulate locomotives and other sources under California law is circumscribed in varying degrees by the CAA and ICCTA. To the extent that ARB has authority to adopt regulations under the CAA, its authority must be harmonized with the ICCTA preemption.

c. California Emission Standards for Other Railyard Sources

ARB has adopted and implemented other regulations that affect diesel sources operating at railyards. The existing measures include the ARB regulations for cargo handling equipment, drayage trucks, transport refrigeration units, and clean diesel fuel.

2. Voluntary Enforceable Agreements

UP Railroad and BNSF Railway have entered into two enforceable agreements with ARB to further reduce emissions in California. The 1998 ARB/Railroads Agreement[47] (often referred to as the Fleet Average Agreement) requires that, by January 1, 2010, NOx emissions from all locomotives operating in the South Coast Air Basin, on average, be equivalent to the lowest emitting line haul locomotives available for purchase in that year (U.S. EPA Tier 2). Under this Agreement, locomotive NOx emissions in the South Coast Air Basin have been reduced by about 67 percent.[48]

The 2005 Agreement[49] with UP and BNSF obligates the railroads to significantly reduce diesel emissions in and around railyards in California. Among the most important elements of the 2005 Agreement are provisions that will significantly clean up the State's biggest railyards, including:

- Health risk assessments for all major railyards,
- Installation of idle reduction devices on intrastate locomotives,
- Dispensing low sulfur fuel in California,
- Adopting a stringent visual emission reduction and repair program,
- Compliance with annual reporting requirements, and
- Community and air district involvement in the preparation of risk assessments, enforcement of Agreement provisions, and the evaluation and development of measures to further reduce impacts on local communities.

ARB estimates that, as a result of the 2005 Agreement, about 400 intrastate locomotives have been equipped with automatic shutdown devices (99 percent of the

[47] ARB, *Memorandum of Mutual Understandings and Agreements, South Coast Locomotive Fleet Average Emission Program*, July 1998.
[48] *Federal Register, Vol. 64, No. 108, p. 30279, July 7, 1999.*
[49] ARB, *ARB/Railroad Statewide Agreement, Particulate Emissions Reduction Program at California Railyards*, June 2005.

intrastate fleet), at least 95 percent of the fuel purchased by the railroads has been low-sulfur fuel, and that at least 99 percent of all units in California are complying with stringent smoke limits. ARB staff provided multiple updates to the Board since 2005 reporting that both UP Railroad and BNSF Railway were on or ahead of schedule to meet all aspects of the 2005 Agreement.

In addition to the two formal agreements, ARB and local air districts have enforceable grant contracts with the railroads to use incentive funds to replace or upgrade existing locomotives with cleaner technology, and to operate those cleaner locomotives for a specified time period (typically 15 years) with a defined region.

IV. IMPACT ANALYSIS

A. Introduction

This chapter presents ARB's analysis of potential impacts on the physical environment that may result from ARB's approval and implementation of the Revised 2010 Commitments. The proposed project's primary purpose is to improve the existing air quality environment surrounding the covered railyards (as described under *Project Objective*) by implementing a binding voluntary agreement whereby the railroads would employ technological changes and/or strategic operational changes. The Revised 2010 Commitments set specific emission reduction performance standards, but do not require any specific actions by the railroads, such as certain equipment upgrades or movement of an activity to another location within the railyard. The railroads may use any combination of technology and/or operational changes to meet the standards. Such changes are at the discretion of the railroads.

The execution and implementation of these Revised 2010 Commitments does not directly and adversely affect the physical environment. CEQA requires, however, an analysis of a project to include any reasonably foreseeable *indirect* physical changes in the environment that may occur as a result of the project.[50] Therefore, this analysis focuses on the environmental consequences potentially resulting from the actions that the railroads may take to comply with Commitments.

The future actions the railroads may choose to take cannot be definitively predicted at this time, as it is at the discretion of the railroads to undertake or not to undertake any operational changes to meet the emission reduction targets. Although CEQA discourages forecasting and speculation, drafting an environmental document necessarily involves some degree of forecasting. ARB has used its best efforts to find out and disclose all that it reasonably can, and this analysis provides as much information as is currently available, without being speculative.

During evaluation of the environmental checklist topics, staff determined that operational changes (as described under *Project Description*) that the railroads will assess and may implement to meet the emission reduction targets (or to reduce railyard health risk without reducing emissions) have the potential to result in changes to the physical environment in the vicinity of the railyards. Staff identified three resource areas that warranted further discussion in this chapter of the FED. The FED checklist in Attachment 1 provides a brief explanation supporting the determination for each of the other resource areas that the project will have no impact.

This analysis of the indirect impacts of complying with the Revised 2010 Commitments is necessarily general and programmatic in nature. The degree of specificity required in a CEQA document corresponds to the degree of specificity inherent in the underlying

[50] CEQA Guidelines, Article 5, §15064(d)(2) and (d)(3).

activity that it describes.[51] The analysis of the indirect effects of the Revised 2010 Commitments need not, and cannot be, as detailed as for specific plans and projects.[52] A more detailed analysis is not reasonably feasible at this time because specific compliance projects are not authorized by the adoption of the Commitments and it is unknown what specific future actions will be undertaken at each railyard to meet the emission reduction targets as any changes are at the discretion of the railroads. Because ARB regulations require ARB's functional equivalent document to describe both potentially beneficial and potentially adverse effects of its proposed actions, this discussion includes a discussion of potential beneficial impacts.[53]

This chapter also includes a description of the environmental setting (existing conditions) for each of the resource areas analyzed at each of the four high-priority yards. The environmental setting is used as the baseline for comparison of potential changes resulting from implementation of the project and determining impact significance.

B. Beneficial Effects

Although the primary focus of conventional CEQA impact assessment is identification and disclosure of adverse environmental impacts, ARB's regulations require the assessment of both beneficial and adverse environmental impacts.[54] The Revised 2010 Commitments establish the level of emissions for future years that cannot be exceeded regardless of growth in cargo or railyard activity. These levels are based on a specific percent reduction from established 2005 emissions. The railroads will accelerate the use of cleaner technology, possibly in combination with operational improvements, to achieve the required emission reductions at each railyard. These actions will help reduce the health risk in communities near the railyards.

In this analysis of the potential environmental impacts of the Revised 2010 Commitments, data for calendar year 2010 represent the existing conditions. We also routinely provide calendar year 2005 numbers for consistency with other documents because ARB developed the Revised 2010 Commitments in response to the results of health risk assessments performed for calendar year 2005 rail operations. The Revised 2010 Commitments themselves use 2005 as the benchmark for setting emissions targets and measuring progress.

[51] CEQA Guidelines, §15146.
[52] CEQA Guidelines, §15146.
[53] Title 17, California Code of Regulations, §60005.
[54] Title 17, California Code of Regulations, §60005.

1. Emission Reductions

Appendix A provides a detailed discussion of ARB's current estimates of diesel PM emissions at each of the four high-priority railyards and expected reductions from both the existing program (adopted ARB and U.S. EPA regulations and agreements) and the Revised 2010 Commitments. Figure F-6 summarizes the net impact of the existing program of adopted U.S. EPA and ARB regulations and agreements plus the Revised 2010 Commitments on emissions at each yard. Figure F-7 graphically illustrates the expected benefits attributable to the Revised 2010 Commitments alone, based on the projected cargo growth levels. Tables F-3 through F-6 provide the numbers used to derive the benefits attributable to the Revised 2010 Commitments at each yard (for further detail, please see Appendix A to this report). The actual benefits realized may change if growth is greater or less than projected.

Figure F-6
Diesel PM Emissions with the Revised 2010 Commitments at the Four High-Priority Railyards

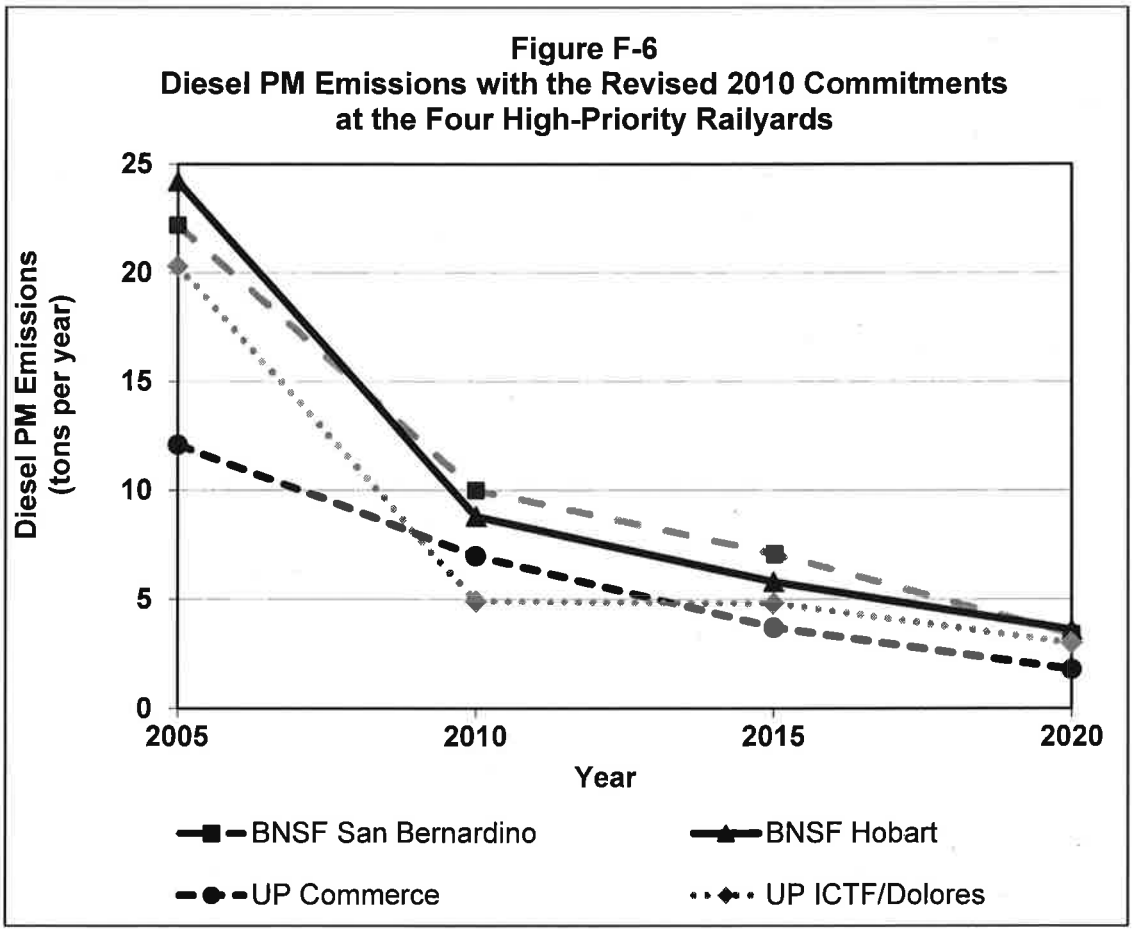

Figure F-7
Percent Diesel PM Reduction Attributable to the Revised 2010 Commitments in 2015 and 2020

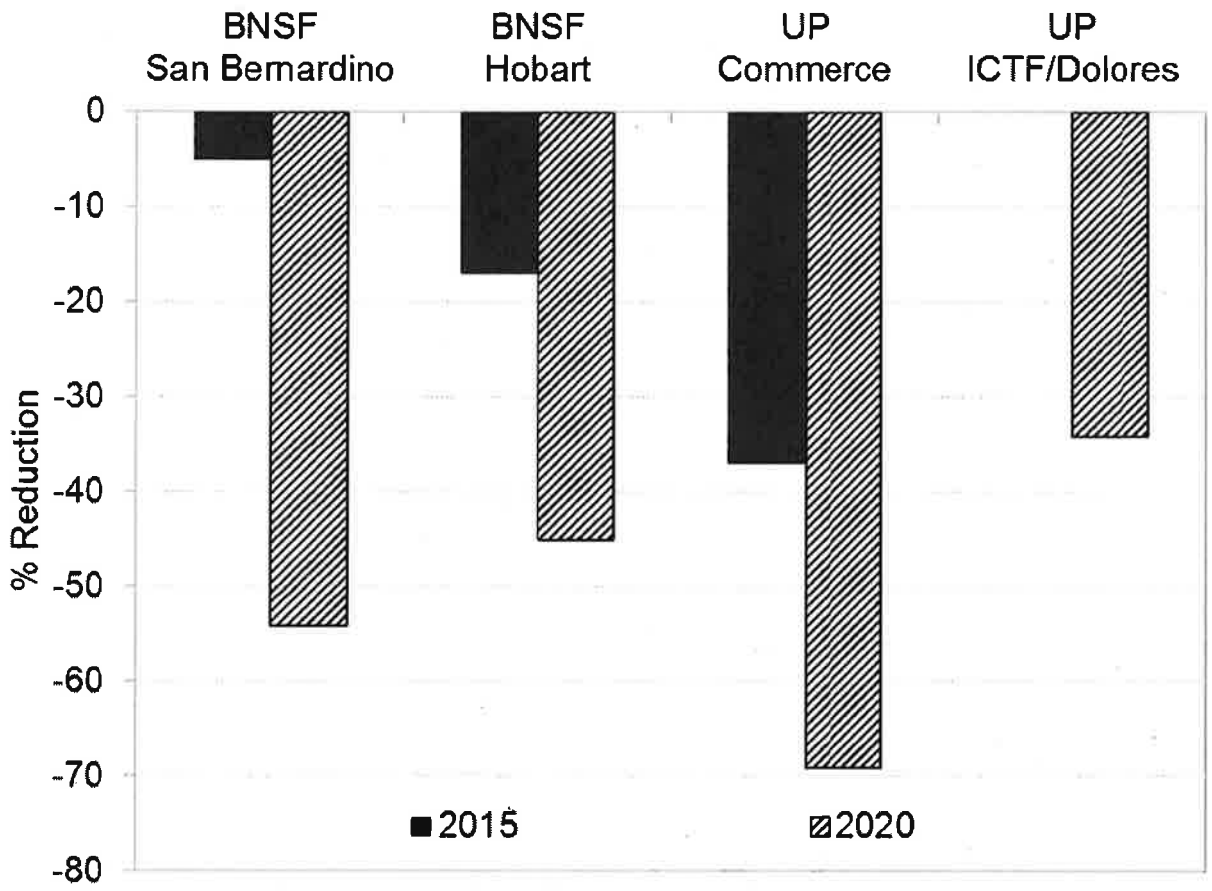

Table F-3
BNSF San Bernardino Railyard
Diesel PM Emissions
(tons per year)

	2005	2010	2015	2020
Existing Program	22.2	10.0	7.5	7.3
Existing Program + Commitments	N/A	N/A	7.1	3.4
Reductions Attributable to the Commitments in Future Year	N/A	N/A	-0.4	-3.9
Percent Reduction Attributable to the Commitments in Future Year	N/A	N/A	5%	53%

Table F-4
BNSF Hobart Railyard
Diesel PM Emissions
(tons per year)

	2005	2010	2015	2020
Existing Program	24.2	8.8	7.0	6.6
Existing Program + Commitments	N/A	N/A	5.8	3.6
Reductions Attributable to the Commitments in Future Year	N/A	N/A	-1.2	-3.0
Percent Reduction Attributable to the Commitments in Future Year	N/A	N/A	17%	45%

Table F-5
UP Commerce Railyard
Diesel PM Emissions
(tons per year)

	2005	2010	2015	2020
Existing Program	12.1	7.0	5.9	5.8
Existing Program + Commitments	N/A	N/A	3.7	1.8
Reductions Attributable to the Commitments in Future Year	N/A	N/A	-2.2	-4.0
Percent Reduction Attributable to the Commitments in Future Year	N/A	N/A	37%	69%

Table F-6
UP ICTF/Dolores Railyards
Diesel PM Emissions
(tons per year)

	2005	2010	2015	2020
Existing Program	20.3	4.9	4.8	4.6
Existing Program + Commitments	N/A	N/A	4.8	3.0
Reductions Attributable to the Commitments in Future Year	N/A	N/A	0	-1.6
Percent Reduction Attributable to the Commitments in Future Year	N/A	N/A	0%	35%

2. Health Risk Reductions

The 2005 Agreement[55] required that health risk assessments (HRAs) be prepared for each of the 17 major or designated railyards in the State. These HRAs were completed in 2007 and 2008, using emission inventories for railyard operations in 2005. The HRAs yield the maximum individual cancer risk (MICR), which is defined as the estimated probability of a potential maximally exposed individual contracting cancer as a result of exposure to toxic air contaminants. The exposure is over a period of 70 years for residential receptor locations, and 40 years for worker receptor locations.

Diesel-related emissions are lower today than in 2005 due to the benefits of ARB's statewide regulations for drayage trucks,[56] cargo handling equipment,[57] transport refrigeration units,[58] and locomotive fuels,[59] as well as the 1998 Agreement[60] and the 2005 Agreement[61] with BNSF and UP to reduce air pollution from rail activities. However, despite the above regulations and agreements, the diesel PM emissions from railyard emission sources continue to pose a significant health risk today to people who live near the four high-priority railyards.

The *June 2010 Staff Report* contains a discussion of the current and projected diesel PM emissions and health risks from each railyard, based on extensive earlier work done by the railroads to develop an inventory of diesel PM emissions for each railyard, and work done by ARB staff to assess the associated health risk at each railyard. The Inventories and the HRAs provide detailed data on the conditions at each railyard during the 2005 calendar year (see *Incorporation of Documents by Reference* in Chapter I). Appendix A updates the emissions, cancer risk, and population exposure estimates for 2010, which establishes the existing conditions for this environmental analysis.

The Revised 2010 Commitments require reductions in diesel PM emissions, which will have a direct and nearly proportional impact on the related cancer and health risk from exposure to those emissions. Staff has already established the relationship between emissions and the resulting excess cancer risk based on the site-specific conditions at each of the four high-priority railyards in the Health Risk Assessments. In the Revised 2010 Commitments, staff used emissions as a surrogate for health risk, since emissions can be most readily tracked.

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[55] *ARB/Railroad Statewide Agreement, Particulate Emissions Reduction Program at California Rail Yards*, June 2005. http://www.arb.ca.gov/railyard/ryagreement/083005mouexecuted.pdf

[56] Title 13, California Code of Regulations, §2027. New section filed November 24, 2008, operative December 24, 2008.

[57] Title 13, California Code of Regulations, §2479. New section filed and operative December 1, 2006.

[58] Title 13, California Code of Regulations, Article 8 §2477. New article and section filed November 10, 2004, operative December 10, 2004.

[59] Title 13, California Code of Regulations, §2282-2285. Amendment filed July 15, 2004, operative August 14, 2004.

[60] *Memorandum of Mutual Understandings and Agreements, South Coast Locomotive Fleet Average Emissions Program*, July 2, 1998. http://www.arb.ca.gov/msprog/offroad/loco_flt.pdf

[61] *ARB/Railroad Statewide Agreement, Particulate Emissions Reduction Program at California Rail Yards*, June 2005.

Table F-7 presents a summary of significant reductions in the projected maximum excess cancer risk expected after implementation of both the Revised 2010 Commitments and the existing program of already adopted ARB and U.S. EPA regulations and agreements. The 2005 Health Risk Assessments for each railyard established the relationship between emissions, location, meteorology, and the resulting exposure and cancer risk to nearby communities. With the exception of the BNSF San Bernardino Railyard, this analysis assumes that changes to the maximum excess cancer risk for future railyard operations are directly proportional to changes in total diesel PM emissions. For BNSF San Bernardino, the 2005 Health Risk Assessment used a source-weighted approach that accounts for the relative impact of diesel PM from each type of emissions source based on its location and proximity to residents. We use that same approach to estimate the current and future risk for this railyard. Because 2010 represents the existing conditions for this proposed project, we show the percent reduction between this year and 2020, unlike Appendix A that displays the changes between 2005 and 2020.

Table F-7
Reduction in Diesel PM Health Risk with the Revised 2010 Commitments at the Four High-Priority Railyards

Railyard	Maximum Individual Cancer Risk for 70-Year Exposure (chances per million)				
	2005	2010 (existing condition)	2015	2020	Reduction (from 2010 to 2020)
BNSF San Bernardino*	2,500	650	500	275	-58%
BNSF Hobart	500	180	120	75	-58%
UP Commerce	500	290	155	75	-74%
UP ICTF/Dolores	800	190	180	120	-37%

* Risk estimates for BNSF San Bernardino Railyard consider the source and location of the diesel PM emissions within the railyard in each year, consistent with the method used to develop the 2005 numbers.

Table F-8 through F-11 provide the details for each railyard to compare the cancer risk and number of people exposed with and without the Revised 2010 Commitments. These tables below show that in 2020, the Revised 2010 Commitments would cut the remaining risk by an additional 30-70 percent, compared to the risk under the existing program in the same year. They would also reduce the number of people exposed to a cancer risk greater than 10 in a million in 2020 by an additional 80-92 percent beyond the existing program. Just as the Revised 2010 Commitments will reduce the diesel PM emissions and cancer risk at the railyards, they will also reduce the non-cancer health impacts.

Table F-8
BNSF San Bernardino Railyard
Estimated Maximum Individual Cancer Risk and Population Exposure

	Excess Maximum Individual Cancer Risk for 70-Year Exposure* (chances per million)			
	2005	**2010**	**2015**	**2020**
Existing Program	2,500	650	510	400
Existing Program + Commitments	N/A	650	500	275
Percent Reduction in Future Year	N/A	N/A	2%	31%
	Number of People Exposed to a Risk >10 in a Million			
Existing Program	350,000	187,000	140,000	137,000
Existing Program + Commitments	N/A	187,000	135,000	69,000
Percent Reduction in Future Year	N/A	N/A	4%	50%

* Estimated cancer risk considers the source and location of the diesel PM emissions within the railyard.

For BNSF San Bernardino, if you compare the rate of reduction in cancer risk over time (Table F-8) to the rate of reduction of diesel PM emissions (Table F-3), you will notice that risk decreases faster than emissions in the earlier years and slower in the out years. This is because the diesel PM emission sources that achieved substantial reductions by 2010 are also the emission sources with the greatest impact on health risk because of their proximity to nearby residents. Drayage trucks, cargo handling equipment, and transport refrigeration units achieved the bulk of their emission reductions by 2010 –these same sources typically have the highest health impact and reduction per unit of emissions because of their proximity to residents.

Table F-9
BNSF Hobart Railyard
Estimated Maximum Individual Cancer Risk and Population Exposure

	Excess Maximum Individual Cancer Risk for 70-Year Exposure (chances per million)			
	2005	**2010**	**2015**	**2020**
Existing Program	500	180	145	140
Existing Program + Commitments	N/A	180	120	75
Percent Reduction in Future Year	N/A	N/A	17%	46%
	Number of People Exposed to a Risk >10 in a Million			
Existing Program	848,000	281,000	240,000	223,000
Existing Program + Commitments	N/A	281,000	192,000	110,000
Percent Reduction in Future Year	N/A	N/A	20%	51%

Table F-10
UP Commerce Railyard
Estimated Maximum Individual Cancer Risk and Population Exposure

	Excess Maximum Individual Cancer Risk for 70-Year Exposure (chances per million)			
	2005	**2010**	**2015**	**2020**
Existing Program	500	290	245	240
Existing Program + Commitments	N/A	290	155	75
Percent Reduction in Future Year	N/A	N/A	37%	69%
	Number of People Exposed to a Risk >10 in a Million			
Existing Program	270,000	178,000	140,000	136,000
Existing Program + Commitments	N/A	178,000	67,000	22,000
Percent Reduction in Future Year	N/A	N/A	52%	84%

Table F-11
UP ICTF/Dolores Railyards
Estimated Maximum Individual Cancer Risk and Population Exposure

	Excess Maximum Individual Cancer Risk for 70-Year Exposure (chances per million)			
	2005	**2010**	**2015**	**2020**
Existing Program	800	190	180	180
Existing Program + Commitments	N/A	190	180	120
Percent Reduction in Future Year	N/A	N/A	0%	33%
	Number of People Exposed to a Risk >10 in a Million			
Existing Program	600,000	156,000	143,000	123,000
Existing Program + Commitments	N/A	156,000	143,000	65,500
Percent Reduction in Future Year	N/A	N/A	0%	47%

3. Pollutants Other Than Diesel PM

ARB staff qualitatively assessed the potential for implementation of the Revised 2010 Commitments to affect emissions of pollutants other than diesel PM at the high-priority railyards. Because locomotives account for the majority of the diesel PM emissions at the high-priority railyards (see Appendix A to this *Supplement to the June 2010 Staff Report*), they will also need to be the primary source of new emission reductions to meet the declining levels. For example, ARB staff previously identified a potential path to achieve the diesel PM emission reduction levels at the BNSF San Bernardino Railyard. This path relies on transition of the entire fleet of switch locomotives assigned to the railyard from Tier 0 to Tier 3 and then Tier 4 levels. For line haul locomotives, the path relies on the transition from the current Tier 2 average levels to 100 percent Tier 4 levels.

Table F-2 shows the federal locomotive emission standards for each regulated pollutant. At the four high-priority railyards, the existing baseline for locomotives is Tier 0 or better since the railroads have discontinued routine use of the uncontrolled, pre-Tier 0 locomotives at these yards (as documented by ARB staff field surveys). As the railroads replace older locomotives or upgrade the engines in those locomotives to Tier 4 levels to meet the diesel PM levels required by the Revised 2010 Commitments, those actions will simultaneously reduce PM, NOx, and HC by about 85-95 percent compared to Tier 0 levels.

For the sulfur oxides (SOx) that contribute to fine particle pollution, ARB staff expects the impact of the Revised 2010 Commitments to be neutral or beneficial due to use of

more fuel-efficient switch locomotives. The significant reductions in SOx emissions from railyard operations occurred earlier this decade when ARB's regulations for low sulfur diesel fuel in all land-based sources went into effect. For greenhouse gases and other pollutants that contribute to climate change, Section VII of the Checklist (see Attachment 1) discusses why staff expects the Revised 2010 Commitments to have a neutral or beneficial impact.

4. Benefits in Other Communities

In response to the Revised 2010 Commitments, ARB staff expects that the railroads will target introduction of the newest, cleanest line haul locomotives to provide interstate service between California and points east, while the cleanest switch locomotives will be operated at the four high-priority railyards or within the region. Based on staff experience with the 1998 ARB/Railroads Locomotive NOx Fleet Average Agreement in the South Coast Air Basin (1998 Agreement), staff anticipates that communities across the State that are not near the four high-priority railyards would receive about 15 percent of the benefits from the lower-emission locomotives brought in to meet the emission levels at the high-priority railyards.[62]

C. Potential Adverse Impacts

This analysis specifically focuses on potential significant, adverse impacts on the physical environment in the context of potential changes from the existing environmental conditions at each of the four high-priority railyards subject to the Revised 2010 Commitments. The analysis includes a description of the physical environmental conditions in the vicinity of the project as they exist at the time the analysis was commenced.[63] ARB has identified three areas of potentially significant adverse impacts that might result from the Revised 2010 Commitments: aesthetics (light), noise, and transportation and traffic. (See Checklist in Attachment 1.)

1. Aesthetics

This section contains a description of the environmental setting and potential impacts associated with implementation of the Revised 2010 Commitments with respect to Aesthetics. Staff identified the potential only for the creation of a new source of substantial light or glare that would adversely affect day or nighttime views in the area.

a. Environmental Setting

The four high-priority railyards are in continuous operation under well-lighted conditions, 24 hours a day, seven days a week. Under existing conditions, there is substantial nighttime light and glare from fixed lighting sources.

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[62] *June 2010 Staff Report*, p. 19.
[63] CEQA Guidelines, Article 9, §15125.

i. BNSF San Bernardino Railyard

The vicinity around the BNSF San Bernardino Railyard includes commercial, industrial, and heavy industrial operations (e.g., warehousing and servicing facilities, etc.) that involve substantial lighting. The lighting standards at the BNSF San Bernardino Railyard are guided by local planning documents, safety requirements, and industry best management practices. The BNSF San Bernardino Railyard area is currently illuminated by a combination of high-pressure sodium and metal halide lamps, which are generally supported on standards between 40 and 120 feet tall. In general, the entire BNSF San Bernardino Railyard is lit to safely accommodate 24 hour operations seven days a week to a level of 1.0 to 3.0 foot-candles. Specifically, the BNSF San Bernardino Railyard currently utilizes:[64]

- Four Cobra style fixtures with metal halide lamps;
- Thirteen 80 feet high fixed metal poles with a combination of high pressure sodium and metal halide lamps;
- Seven 120 feet high mast metal fixtures with high pressure sodium lamps; and
- Forty 80 feet high wooden fixtures with high pressure sodium bulbs.

ii. BNSF Hobart Railyard

The vicinity around the BNSF Hobart Railyard includes commercial, industrial, and heavy industrial operations (e.g., UP Commerce Railyard, warehousing, and servicing facilities, etc.), and the I-710 freeway (which bisects the BNSF Hobart Railyard) that involve substantial lighting. The lighting standards at the BNSF Hobart Railyard are guided by local planning documents, safety requirements, and industry best management practices. The BNSF Hobart Railyard area is currently illuminated by metal halide and high-pressure sodium light fixtures, most of which are supported on standards between approximately 80 and 100 feet high. In general, the entire BNSF Hobart Railyard is lit to safely accommodate 24 hour operations seven days a week to a level of 1.0 to 3.0 foot-candles. Specifically, the BNSF Hobart Railyard currently utilizes:[65]

- Thirty-four Cobra style fixtures with high pressure sodium lamps;
- Fifty-eight metal high mast poles with high pressure sodium lamps;
- Eight Musco poles with high pressure sodium lamps;
- Twenty-one wooden poles with high pressure sodium lamps; and
- Mounted (without poles) metal halide lamps on the inbound and outbound lanes.

[64] ARB staff, Harold Holmes, communication with CEA Consulting, March 1, 2011.
[65] ARB staff, Harold Holmes, communication with CEA Consulting, March 1, 2011.

iii. UP Commerce Railyard

The vicinity around the UP Commerce Railyard includes commercial, industrial, and heavy industrial operations (e.g., BNSF Hobart Railyard, warehousing, and servicing facilities, etc.), and the I-710 freeway (which bisects the UP Commerce Railyard) that involve substantial lighting. The lighting standards at the UP Commerce Railyard are guided by local planning documents, safety requirements, and industry best management practices. The UP Commerce Railyard area is currently illuminated by 336 high-pressure sodium light fixtures (lamps), most of which are supported on standards between approximately 80 and 100 feet high. In general, the entire UP Commerce Railyard site is currently lit to safely accommodate 24 hour operations seven days a week to a standard lighting level 1.0 to 3.0 foot-candles. Specifically, the UP Commerce Railyard currently utilizes:[66]

- Twenty-seven wooden poles with Cobra style single lamp street lighting;
- Seventeen wooden poles with one-lamp floodlights;
- Twenty-seven wooden or metal poles with two-lamp floodlights;
- Twenty ring style high mast towers with 12 lamps;
- Four basket style high mast towers with 8 lamps; and
- Eight lattice style high mast towers with 8 lamps.

iv. UP ICTF/Dolores Railyards

The vicinity around the UP ICTF/Dolores Railyards includes industrial and heavy industrial operations (e.g., industrial refining facilities, container and truck parking, and servicing facilities, etc.), and the I-405 highway that involve substantial lighting. The lighting standards at the UP ICTF/Dolores Railyards are guided by local planning documents, safety requirements, and industry best management practices. The UP ICTF/Dolores Railyards area is currently illuminated by approximately 596 high-pressure sodium light fixtures supported on standards between 80 and 100 feet high. The loading areas are currently lit using high mast lighting with six, seven, or eight 1000-watt fixtures, at 300 feet spacing, with 80 feet standards mounted on concrete pedestals. The main entrance, the U.S. Customs area, the train entrance area, the guest automobile parking area, the storage area, and the maintenance and guardhouse area are currently lit using 40 feet lighting standards with single and double luminaries using Cobra-type lighting fixtures, with a mix of 400-watt and 250-watt fixtures, supported by standard street lighting poles and fixtures.

In general, the entire UP ICTF/Dolores Railyards site is currently lit to safely accommodate 24 hour operations seven days a week to a standard lighting level of 1.0 to 3.0 foot-candles. The total site area lighting demand at peak use periods is

[66] ARB staff, Harold Holmes, communication with CEA Consulting, March 1, 2011.

approximately 530 kilowatts. Specifically, the UP ICTF/Dolores Railyards currently utilize:[67]

- Seventy-four high mast towers with 8 lamps;
- One high mast tower with 4 lamps;
- Sixty-eight wooden poles with street lighting (Cobra style) single lamp;
- Thirty wooden poles with street lighting (Cobra style) back to back (total of 2 lamps);
- Twenty-four wooden poles with floodlights (2 lamps); and
- Seven wooden poles with floodlights (4 lamps).

b. Impacts Analysis

During the initial review of the project, staff determined that the potential for the creation on new sources of light or glare is the only potentially significant impact under 'Aesthetics' warranting further analysis.

The Revised 2010 Commitments themselves do not recommend or propose any future changes that would result in changes in lighting or glare. However, the railroads have committed to evaluate possible site operational changes at the railyards in response to requests from the public (see *Project Description* for discussion of operational changes). A railroad may decide to incorporate some feasible site operational changes into its emission reduction plans. Some of these changes could involve changes in locations of particular lights at a railyard (e.g., lighted cranes could be moved due to moving of cargo handling operations to a different part of a railyard).

It is unknown at this time what specific operational changes, if any, will be taken at each railyard. Therefore, ARB cannot provide a more detailed analysis of potential light and glare impacts at the particular railyards. ARB staff does not anticipate that potential changes in operations would lead to changes in light and glare because, as described in the environmental setting above, the railyards are already substantially lighted and any movement of individual lights are not expected to change the existing light and glare from these sights.

Although considered unlikely, it is possible that a railroad could shift operations in a way that affects the lighting and glare at any of the affected yards. The siting of particular lights around the railyard, as part of an operational change, may or may not be subject to further approvals by local land use authorities or further project specific environmental review (see potential mitigation below). In view of the uncertainty about future actions that could affect light and glare, this analysis takes a conservative approach and considers this impact to be potentially significant.

[67] ARB staff, Harold Holmes, communication with CEA Consulting, March 1, 2011.

c. Potential Mitigation

ARB does not have any land-use authority over railyard operations, and therefore, cannot require project-level mitigation that involves railyard operations. ARB's authority over the railyards is limited to the provisions outlined in the Revised 2010 Commitments. ARB could remove the requirements in the Revised 2010 Commitments specifically requested by community members that the railroads evaluate and consider operational changes.

It is not clear to ARB what local permitting authority, if any, may apply to future decisions by the railroads to change lighting at the railyards. It is infeasible, at this time, to determine whether local permitting authority (that could trigger further environmental review and mitigation) would be applicable to potential future lighting changes, and therefore whether any mitigation would be required for such changes. First, any applicable local permitting authority may be preempted by the ICCTA.[68] Furthermore, even if lighting changes were subject to local permitting authority, it is not clear whether a permit would be discretionary or ministerial because the nature and scope of potential lighting changes is too speculative to identify at this time.[69] Therefore, ARB cannot identify feasible mitigation measures to reduce or eliminate identified potentially significant light and glare impacts. Consequently, the FED takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that the potentially significant impacts to aesthetics (light and glare) resulting from potential operational shifts may be unavoidable.

2. Noise

This section includes a description of the environmental setting (e.g., acoustic fundamentals, types of sensitive land uses and sources in the project area) and an evaluation of potential noise (and vibration) impacts associated with implementation of the Revised 2010 Commitments.

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[68] Preemption is factually based. (See *New York Susquehanna & Western Railway Corporation v. Jackson* (3d Cir.2007) 500 F.3d 238, 252-253). To the extent that local agencies have general code provisions establishing standards for light and glare emitted from a facility, they may be considered to be standards of general applicability and not subject to preemption under the ICCTA. (*Association of American Railroads (AAR) v. the South Coast Air Quality Management District* (9th Cir. 2010) 622 F.3d 1094, 1098; *New York Susquehanna & Western Railway Corporation v. Jackson, supra,* 500 F.3d at pp. 252-253; *Green Mountain Railroad Corp. v. State of Vermont* (2d Cir. 2005) 404 F.3d 638, 643.) To the extent such local regulations impair the railroads' ability to operate, and to manage their operations, the local rules could be preempted by the ICCTA, even if such rules are generally applied. (*New York Susquehanna & Western Railway Corporation v. Jackson, supra,* 500 F.3d at pp. 252-253.).

[69] Only discretionary permits trigger CEQA review and mitigation requirements. (Public Resources Code, §21080, subds. (a), (b)(1).)

a. Environmental Setting

i. Acoustic Fundamentals

A sound level is expressed in the decibel (dB) scale, which is the logarithmic ratio of one sound quantity to a reference sound pressure. For sound pressure in air, the standard reference quantity is generally considered to be 20 micropascals, which directly corresponds to the threshold of human hearing. The use of the decibel is a convenient way to handle the million-fold range of sound pressures to which the human ear is sensitive. A decibel is logarithmic; it does not follow normal algebraic methods and cannot be directly added. For example, a 65 dB source of sound, such as a truck, when joined by another 65 dB source results in a sound amplitude of 68 dB, not 130 dB (i.e., doubling the source strength increases the sound pressure by 3 dB). A sound level increase of 10 dB corresponds to ten times the acoustical energy, and an increase of 20 dB equates to a hundred-fold increase in acoustical energy.

The loudness of sound perceived by the human ear depends primarily on the overall sound pressure level and frequency content of the sound source. The human ear is not equally sensitive to loudness at all frequencies in the audible spectrum.

Noise can be generated by a number of sources, including mobile sources (transportation noise sources) such as automobiles, trucks, and airplanes; and stationary sources (non-transportation noise sources) such as construction sites, machinery, and commercial and industrial operations. As acoustic energy spreads through the atmosphere from the source to the receiver, noise levels attenuate (decrease) depending on ground absorption characteristics, atmospheric conditions, and the presence of physical barriers (walls, building façades, berms). Noise generated from mobile sources generally attenuates at a rate of 4.5 dB per doubling of distance. Stationary noise sources spread with more spherical dispersion patterns, which attenuate at a rate of 6 to 7.5 dB per doubling of distance.

The response of the ear to sound is dependent on the frequency of the sound. The human ear has peak response around 2,500 to 3,000 hertz and has a relatively low response at low frequencies. This has led to the concept of weighting scales. In the "A-weighting" scale, the sound pressure levels for the lower frequency bands and high frequency bands are reduced by certain amounts before they are being combined together to give one single sound pressure level value. This value is designated as dB(A). The dB(A) is often used as it reflects more accurately the frequency response of the human ear. Weighting networks are often incorporated in measuring equipment to give readings in dB(A).[70]

Atmospheric conditions such as wind speed, turbulence, temperature gradients, and humidity may additionally alter the propagation of noise and affect levels at a receiver.

[70] Environmental Protection Department, Government of the Hong Kong Special Administrative Region, Educational Package on Sound and Noise.

Furthermore, the presence of a large object or objects (e.g., barrier, topographic features, and intervening building façades) between the source and the receptor can provide significant attenuation of noise levels at the receiver. The amount of noise level reduction or "shielding" provided by a barrier primarily depends on the size of the barrier, the location of the barrier in relation to the source and receivers, and the frequency spectra of the noise. Natural barriers such as berms, hills, or dense woods, and human-made features such as buildings and walls, may be used as noise barriers.

ii. Vibration

Vibration is the periodic oscillation of a medium or object with respect to a given reference point. Sources of vibration include natural phenomena (e.g., earthquakes, volcanic eruptions, sea waves, landslides) and those introduced by human activity (e.g., explosions, machinery, traffic, trains, construction equipment). Vibration sources may be continuous (e.g., operating factory machinery) or transient in nature (e.g., explosions). Vibration levels can be depicted in terms of amplitude and frequency, relative to displacement, velocity, or acceleration.

iii. Existing Sources of Noise and Vibration

The four high-priority railyards covered by the Revised 2010 Commitments are large, existing industrial-type operations that already run 24 hours a day, seven days a week, with on-site and entering/exiting diesel equipment. The physical scale, frequency of activity, noise, and vibration from these operations are part of the existing conditions.

b. Regulatory Setting

The noise at railroads is regulated by U.S. EPA and Federal Railroad Administration (FRA) noise emission regulations, and enforced by the FRA:

- Title 49 Code of Federal Regulations (CFR) Part 229.129 regulates locomotive horn noise to between 96 and 110 dB(A) at 100 feet forward of the locomotive direction of travel. This regulation is a safety requirement for railroads, in that it specifies the minimum horn noise required to warn motorists of trains approaching train crossings, as well as the methods that must be used to determine compliance with this requirement.
- Title 40 CFR Part 201 governs noise from locomotives, railcar operations, retarders, car coupling, and load cell test stands. Railroads are responsible for compliance and defective equipment, and are required to correct any noise defect, remove defective equipment from service and to the nearest facility for repairs, or modify the car coupling procedure to bring it within the federal noise limits. The U.S. EPA noise standards at Title 40 CFR Part 201 are summarized in Table F-12 below:

Table F-12
Summary of U.S. EPA Noise Standards
(Title 40 CFR Part 201)

Noise Source	Decibel Level, dB(A)	Measurement Location
Pre-1980 locomotives		
Stationary, Idle	73	30 meters
Stationary, all other throttle settings	93	30 meters
Moving	96	30 meters
Post-1979 locomotives		
Stationary, Idle	70	30 meters
Stationary, all other throttle settings	87	30 meters
Moving	90	30 meters
Switch locomotives (Switchers)		
Stationary, Idle	70	30 meters
Stationary, all other throttle settings	87	30 meters
Moving	90	30 meters
Alternative stationary and moving standard for pre-1980 switchers	65	receiving property, if all switchers at a facility are in compliance with this standard
Railcars		
Moving 45 mph or slower	88	30 meters
Moving faster than 45 mph	93	30 meters
Other railyard equipment		
Retarders	83	receiving property
Car coupling standard	92	receiving property
Alternative car coupling standard	Can exceed 92 decibels if the cars representative of those found to exceed standard are coupled at similar locations at speeds of 8 mph or less	
Load cell tests	78	30 meters
Alternative load cell standard	65	receiving property, if all load cells at a facility are in compliance with this standard
Alternative standard (if the measurement procedures cannot be complied with)	65	receiving property is located more than 120 meters from load cell

c. Impacts Analysis

The Revised 2010 Commitments will not lead to changes in how the railroads comply with existing U.S. EPA and FRA noise regulations. ARB anticipates that noise will decrease in response to the Revised 2010 Commitments. ARB staff anticipates that the railroads will need to deploy new and upgraded lower-emitting locomotives in significant numbers to meet the declining emission levels. These lower-emitting locomotives are quieter than the current models. The switch locomotives, which operate primarily in the railyard assembling railcars into trains, are already transitioning to generator-set (gen-set) models. The N-Viro Motive gen-set has noise reduction levels of up to 85 percent or higher, with the resultant noise levels similar to on-highway trucks.[71] When the new advanced technology line haul locomotives are available, staff expects those units to be roughly 10 to 30 percent quieter than the current locomotives that will be replaced. Staff also anticipates the possibility that some of the existing diesel cargo handling equipment at railyards (such as cranes and yard trucks) may be replaced with fully electric models that are noticeably quieter.

If operational changes involving construction (such as electric infrastructure for cranes) are implemented, there could be short-term construction-related noise impacts but the nature and scope of these impacts are unknown at this time. Generally, construction generated noise levels would be intermittent and temporary in nature and similar to the types of noise sources and associated levels that currently exist within these industrial settings.

The Revised 2010 Commitments would not increase the total noise at a railyard on an on-going basis, but may change the location of some existing noise sources within the railyard. As a result of operational changes, noise from a maintenance facility or cargo handling equipment operation could be moved to a different location within a railyard.

Generally, staff does not anticipate that movement of a maintenance facility from one part of the railyard would result in significant adverse noise impacts because noise from this source is a small subset of the overall noise at the railyards. However, it is unknown at this time what specific operational changes, if any, will be taken at each railyard.

Therefore, ARB cannot predict at this time what potential noise impacts could arise from operational changes, including movement of a maintenance facility. As discussed under Aesthetics, operational changes, such as movement of a maintenance yard, may or may not be subject to further environmental review under permitting requirements by local land use agencies. In light of the uncertainty of possible noise impacts arising from operational changes, and because this type of shift may not be subject to further environmental review whereby mitigation could be incorporated, this analysis takes a conservative approach and considers this to be a potentially significant impact.

[71] National Railway Equipment Company: http://www.nationalrailway.com/nviro.asp. Web archive, May 5, 2011.

d. Potential Mitigation

ARB does not have any land-use authority over railyard construction and operations, and, therefore, cannot require project-level mitigation that involves railyard operations. ARB's authority over the railyards is limited to the provisions outlined in the Revised 2010 Commitments. ARB could remove the requirements in the Revised 2010 Commitments specifically requested by community members that the railroads evaluate and consider operational changes.

The railroads may or may not be subject to further project-level compliance with applicable permits issued at the local level, which routinely require mitigation to avoid impacts. (See discussion under Aesthetics, Potential Mitigation.) Therefore, ARB cannot identify feasible mitigation measures to reduce or eliminate identified potentially significant noise impacts. Consequently, the FED takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that the potentially significant impacts to noise resulting from potential operational shifts may be unavoidable.

3. Transportation and Traffic

The section includes a description of the environmental setting and potential indirect impacts associated with implementation of the Revised 2010 Commitments with respect to transportation and traffic.

a. Environmental Setting

i. BNSF San Bernardino Railyard

Trucks usually enter the railyard through the main ingress on West 4th Street. Once in the railyard, containers and trailers are parked in the eastern section of the intermodal area, east of Mt. Vermont Avenue.[72] In the data available for the time period between May 1, 2005 and April 30, 2006, BNSF container trucks generated about 1,700 trips a day, equaling about 620,000 trips per year.[73] The freeway route taken by most trucks on exiting the railyard is the I-215.[74] Assuming that the number of truck trips is proportionate to the number of container lifts, the number of truck trips is approximately 500,000 per year in 2010 for the BNSF San Bernardino Railyard.

[72] ENVIRON International, *San Bernardino TAC Emissions Inventory*, January 2008, p. 2-1.
[73] ENVIRON International, *San Bernardino TAC Emissions Inventory*, January 2008, p. 6-3.
[74] Air Resources Board, *Health Risk Assessment for the BNSF Railway San Bernardino Railyard*, June 2008, p. 19.

ii. BNSF Hobart Railyard

Trucks enter the intermodal area at the ingress at the western end of Sheila Street and then travel to the western end of the railyard, and depart from the northwest corner of the railyard. Street-legal yard trucks, which transport containers between the main railyard and the two satellite areas, were also categorized as on-road container trucks. Yard trucks enter and exit the railyard at a gate near the southwest corner of the railyard and travel along East 26th Street to the two satellite areas.

In the data available are for the time period between May 1, 2005 and April 30, 2006, BNSF container trucks generated about 3,530 trips a day, equaling 1,289,000 trips per year. In addition, BNSF on-site contractors operate a fleet of on-road trucks to move empty containers to off-site lots and other facilities. These vehicles make approximately 1,300 trips a day (474,500 trips per year) from the contractor gate separate from the other entrance and exit gate for other container trucks.[75] BNSF Hobart Railyard is supported by the small BNSF Commerce-Eastern domestic container intermodal railyard, which had another approximately 204,000 truck trips in 2005,[76] giving a total of approximately 1,970,000 truck trips for BNSF Hobart Railyard. The freeway route taken by container trucks on exiting the railyard is the I-710.[77] Assuming that the number of truck trips is proportionate to the number of container lifts, the number of truck trips is approximately 1,595,000 per year in 2010 at the BNSF Hobart Railyard.

iii. UP Commerce Railyard

Truck traffic enters the railyard gate complex from East Washington Boulevard. On-road heavy heavy-duty trucks receive containers from or deliver containers to the UP Commerce Railyard.[78] In the data available for the year 2005, UP container trucks generated about 1,025 trips a day (374,000 trips per year).[79] The predominant freeway route taken by trucks on exiting the gate complex is the I-710.[80] Prior to 2005, UP moved the Commerce railyard main truck gate entrance further west from nearby residents living just west of I-710 and Washington Boulevard. Assuming that the number of truck trips is proportionate to the number of container lifts, the number of truck trips for 2010 is estimated at 465,000 for the UP Commerce Railyard.

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[75] Air Resources Board, *Health Risk Assessment for the BNSF Railway Hobart Railyard*, November 2007, pp. 30-34.
[76] ENVIRON International, *Commerce-Eastern Railyard TAC Emission Inventory*, December 2006, pp. 6-2 – 6-4.
[77] Air Resources Board, *Health Risk Assessment for the BNSF Railway Hobart Railyard*, November 2007, p. 45.
[78] Sierra Research, *Toxic Air Contaminant Emissions Inventory and Dispersion Modeling Report for the Commerce Rail Yard, Los Angeles, California*, January 2007, pp. i, 6.
[79] Sierra Research, *Toxic Air Contaminant Emissions Inventory and Dispersion Modeling Report for the Commerce Rail Yard, Los Angeles, California*, January 2007, p. 25.
[80] Air Resources Board, *Health Risk Assessment for the Union Pacific Railroad Commerce Railyard*, November 2007, p. 40.

iv. UP ICTF/Dolores Railyards

Truck traffic enters the railyard gate complex from East Sepulveda Boulevard.[81] Trucks receive containers from or deliver containers to the UP ICTF Railyard. In the data available for the year 2005, UP container trucks generated about 2,575 trips a day (940,000 trips per year).[82] The predominant freeway route taken by trucks on exiting the gate complex is the I-5, although about 23 percent of trucks take the I-405 South to the I-710.[83] Assuming that the number of truck trips is proportionate to the number of container lifts, the number of truck trips is approximately 675,000 per year in 2010 for the UP ICTF/Dolores Railyards.

It should be noted that the UP ICTF Modernization Plan includes a proposal to move the main gate located at Sepulveda west to Alameda Street to reduce the potential for truck idling emissions to affect nearby Long Beach residents. The UP Modernization Plan is currently being reviewed under an Environmental Impact Report (EIR) being prepared by the South Coast Air Quality Management District.[84]

b. Impacts Analysis

The Revised 2010 Commitments themselves do not recommend or propose any future changes that would result in any changes in traffic because the project provides a standard for reduced emissions and does not specify any specific methods for meeting that standard. The Revised 2010 Commitments would not increase cargo activity at the railyards, which is instead driven by economic activity and customer decisions. As a result, staff does not expect the railroads to change the number of trucks entering and exiting the yards in response to the Revised 2010 Commitments.

Implementation of the Revised 2010 Commitments could improve the current conditions to the extent that the railroads continue to seek greater operational efficiency to save fuel and to meet the declining emission caps in the Revised 2010 Commitments. One way to implement operational efficiency is to seek changes that reduce idling time and provide for faster flow of traffic into and out of the yards. For example, BNSF installed an automatic truck gate system at BNSF San Bernardino Railyard. The BNSF automated truck gate system provided significant reductions in truck queuing times and reduced truck operational time within the railyard up to 50 percent. It is also possible that the reduced health risk under the Revised 2010 Commitments will help the applicants obtain funding for more grade separation infrastructure projects and

[81] Sierra Research, *Toxic Air Contaminant Emissions Inventory and Dispersion Modeling Report for the Dolores and ICTF Rail Yards, Long Beach, California*, December 2007, p. 38.
[82] Air Resources Board, *Health Risk Assessment for the UP Intermodal Container Transfer Facility (ICTF) and Dolores Railyards*, April 2008, p. 38.
[83] Sierra Research, *Toxic Air Contaminant Emissions Inventory and Dispersion Modeling Report for the Dolores and ICTF Rail Yards, Long Beach, California*, December 2007, p. APP-114.
[84] Memorandum of Agreement Between the Intermodal Container Facility Joint Powers Authority and the South Coast Air Quality Management District for the Preparation of an Environmental Impact Report Specific to the Modernization of the Intermodal Container Transfer Facility, May 16, 2008.

expedited truck access routes that reduce the train-vehicle interface. Grade separations would improve the level of service for both passenger and freight vehicles on roadways that intersect the tracks.

If operational changes involving construction (like electric infrastructure for cranes) are implemented, there could be short-term construction-related transportation and traffic impacts but the nature and scope of these impacts are unknown at this time. Generally, construction-related traffic impacts would temporary, limited to the period of construction, and would not result in long-term changes in roadway character or significantly increase the number of annual daily trips.

It is unknown at this time whether a railroad may choose to move a truck gate location as an operational change to reduce diesel PM or where at the three railyards such gate movements could occur (applies to all of the railyards except UP Commerce where the truck gate was already moved to lessen the community impacts). Therefore, at this time, ARB cannot provide a more detailed analysis of potential truck route impacts on surface streets associated with possible changes in gate locations. As discussed under Aesthetics, the movement of a truck gate, as part of an operational change at a facility, may or may not be subject to further approvals by local land use authorities or further project specific environmental review. In light of the uncertainty about future actions potentially affecting traffic, this analysis takes a conservative approach and considers this impact to be potentially significant.

c. Potential Mitigation

ARB does not have any land-use authority over railyard operations, and therefore, cannot require project-level traffic mitigation that involves railyard operations. ARB's authority over the railyards is limited to the provisions outlined in the Revised 2010 Commitments. ARB could remove the requirements in the Revised 2010 Commitments specifically requested by community members that the railroads evaluate and consider operational changes.

The railroads may or may not be subject to project-level compliance with applicable permits issued at the local level, which routinely require mitigation to avoid impacts which could minimize these impacts to a level of less than significance. (See discussion under Aesthetics, Potential Mitigation.) Therefore, ARB cannot identify feasible mitigation measures to reduce or eliminate identified potentially significant traffic impacts. Consequently, the FED takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that the potentially significant impacts to transportation and traffic resulting from potential operational shifts may be unavoidable.

D. Other CEQA Considerations

In considering the universe of potential impacts that could result from approval and implementation of the Revised 2010 Commitments, ARB staff identified and evaluated one possible impact that does not fit neatly into the established impact categories. ARB staff considered the potential for the railroads to meet the declining emission caps under the Revised 2010 Commitments by shifting activity from one of the four high-priority railyards to other railyards. ARB staff concludes that it would be highly unlikely to occur and, even if it occurred, existing constraints would severely limit the amount of activity that could possibly be shifted.

Staff evaluated the factors that would influence this possibility – the location of alternative railyard(s), feasibility of moving operations based on the type of railyard and cargo and the capacity of any alternative railyard(s) to absorb additional activity. Staff's analysis indicates that this environmental impact is highly unlikely due to physical, operational, and capacity constraints at the other railyards in the region, as described below.

1. Background

a. Intermodal Railyards

In 2005, the four high-priority railyards handled roughly 75 percent of the total containers moved by UP and BNSF at their major off-dock intermodal railyards in California. All four are intermodal railyards, which are railyards whereat cargo arrives and departs via two different transport modes – train or truck. The cargo handled by these yards is typically in international shipping containers (a standard 20 or 40 feet in length) or domestic trailers (a standard 48 or 53 feet in length). Cargo is moved in containers or trailers by a truck for a short distance and transported on a train for longer distances. To transfer containers and trailers between train and truck, an intermodal railyard must have paved surfaces and a substantial distance between tracks to accommodate the needed cranes, yard trucks, and on-road trucks. An intermodal railyard may be configured so that it only handles shipping containers or trailers holding international or domestic cargo, or it may be configured to handle a combination of the two. A railyard that is designed for one type of cargo may not be able to readily accommodate the other.

b. Classification Railyards

The other primary type of railyard is a classification railyard where all of the cargo comes in by train and leaves by train. Railcars already loaded with containers or trailers are moved around a series of tracks by switch locomotives that disassemble an incoming train and assemble or build a new outgoing train for long distance transport. Classification railyards are distinguished by many rail sidings or segments of track close together where railcars can be moved, temporarily stored, and retrieved. Major

classification railyards typically also support large locomotive refueling and maintenance operations. This type of railyard typically does not have paved areas, truck access, or cranes because switch locomotives do all of the necessary work.

2. Ability to Shift Rail Activity

BNSF and UP are competitors. Each uses its own system of railyards, equipment, and track (except for the shared Alameda Corridor that serves the Ports of Los Angeles and Long Beach). Table A-5 in Appendix A of this document shows the container lift activity and capacity at each of the four high-priority yards.

a. BNSF

BNSF San Bernardino and BNSF Hobart (BNSF Commerce-Eastern, a small spillover domestic intermodal railyard one mile east from BNSF Hobart, was closed in 2008-2009) are that railroad's intermodal facilities in Southern California. The nearest alternative BNSF intermodal railyards are located in the Port of Oakland and Stockton, California – both of which are at or near capacity. Therefore, it is not foreseeable that BNSF could or would shift significant levels of container activity from Southern to Northern California in response to the Revised 2010 Commitments.

b. UP

UP's largest intermodal railyards in Southern California are the two high-priority yards, UP Commerce, (which handles a mix of domestic (75 percent) and international cargo (25 percent)) and UP ICTF/Dolores (which is close to the ports and handles nearly all international cargo). UP Commerce has an estimated capacity of 510,000 container lifts and UP ICTF has current estimated capacity of 760,000 container lifts. The other two UP intermodal railyards in Southern California are UP Los Angeles Transportation Center (LATC) and UP Industry, both domestic container facilities, with estimated capacities of 340,000 and 200,000 container lifts.

UP's four off-dock southern California intermodal railyards have a combined container lift capacity of 1.8 million.[85] In 2005, the four UP intermodal railyards combined handled about 1.4 million container lifts.[86] In 2010, this activity level dropped to about 1.3 million container lifts,[87] an overall decline of about seven percent. Based on 2010 figures, UP had about 500,000 container lifts of off-dock railyard capacity remaining in Southern California.

[85] Los Angeles County Metropolitan Transportation Authority, *Technical Memorandum – I-710 Railroads Goods Movement Study, WBS Task ID:160.10.50*, February 2009, pp. 22-24.
[86] Los Angeles County Metropolitan Transportation Authority, *Technical Memorandum – I-710 Railroads Goods Movement Study, WBS Task ID:160.10.50*, February 2009, p. 18.
[87] United States Securities and Exchange Commission, 2010 Form 10-K, UP Corporation, p. 15.

If the proposed expansion at the UP ICTF facility proceeds, this Modernization Project will double the capacity of that facility, from 760,000 to 1.5 million lifts, and consolidate UP's international cargo operations. Under the Revised 2010 Commitments, UP has agreed to meet the declining emission caps at the combined UP ICTF/Dolores Railyards, including any additional operations resulting from growth or the Modernization Project.

UP LATC Railyard and UP Industry Railyard are primarily domestic intermodal railyards. As of 2010, the combined container lift volume for the two yards was 457,000,[88] leaving an estimated maximum additional lift capacity of about 150,000. The combination of the lift capacity, physical land constraints that restrict expansion, and operational constraints due to the focus of UP LATC and UP Industry Railyards on processing domestic containers, makes it highly unlikely that UP would choose to shift significant levels of lift activity from one of the UP high-priority railyards to these alternative locations in response to the Revised 2010 Commitments.

The closest other large UP international container intermodal facilities in California are UP Oakland, about 400 miles away, and UP Lathrop, south of Stockton. ARB staff considered whether UP could transfer activity from UP Commerce or UP ICTF/Dolores to one of these alternative locations and determined that transfers to the alternative sites were neither reasonable nor feasible. UP Oakland and Lathrop were ruled out because of distance and the limited lift capacity remaining at those two Northern California railyards.

[88] United States Securities and Exchange Commission, 2010 Form 10-K, UP Corporation, p. 15.

V. CUMULATIVE AND GROWTH-INDUCING IMPACTS

This chapter evaluates the potential for the Revised 2010 Commitments, in combination with other existing and planned projects, to result in cumulatively significant environmental impacts.

A. Introduction

CEQA requires that the cumulative impacts of a proposed project be addressed in an environmental document when the project's incremental effect combined with the effects of other projects is cumulatively considerable. If an environmental effect is not "cumulatively considerable," a lead agency need not consider that effect significant, but shall briefly describe its basis for concluding that the incremental effect is not cumulatively considerable. Cumulative impacts are impacts on the environment that result from the incremental impacts of a proposed action when added to other past, present and reasonably foreseeable future actions. Such impacts can result from individually minor but collectively significant actions taking place over time.

B. Staff Methodology

The CEQA Guidelines set forth two methods of identifying cumulative impacts related to development projects. One method is based on adopted projections within a given geographic area included in an adopted general plan or certified environmental document. The other method is based on a list of past, present and reasonably foreseeable future projects that could result in cumulative impacts in combination with the proposed project. This discussion is guided by the standards of practicality and reasonableness, and focuses on the cumulative impacts to which the identified other projects contribute.

To determine whether cumulative impacts could occur as a result of the proposed project, staff considered development as identified at build-out conditions in both the general plan EIRs for the cities in which the four railyards are located and recent and projected projects that are in the vicinity of the four railyards, including the Port of Long Beach's proposed and ongoing projects. For the environmental topics checked 'No Impact' on the checklist, the project would not be expected to make any contribution to potential cumulative impacts whatsoever. Therefore, the focus of staff's analysis is only on aesthetics, noise, and transportation and traffic.

The City of San Bernardino General Plan[89] EIR was referred to in order to identify development projects located near the BNSF San Bernardino Railyard facility.

The City of Commerce General Plan[90] was referred to in order to identify development projects located near the BNSF Hobart and UP Commerce Railyards.

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[89] *Final San Bernardino General Plan Update and Associated Specific Plans: Environmental Impact Report*, September 2005,

The City of Carson General Plan EIR[91] was referred to in order to identify development projects located near the Dolores Railyard facility.

The City of Long Beach General Plan: The Long Beach 2030 Plan, currently in the works, will be an update to the existing general plan.[92] The noise and transportation elements of the existing general plan were adopted in 1975 and 1991, respectively.[93]

The City of Long Beach General Plan elements for noise (1975) and traffic (1991) are out of date, so ARB staff chose to use more up to date information from the Port of Long Beach documents to evaluate the potential cumulative impacts from implementation of the Revised 2010 Commitments at the UP ICTF facility in Long Beach.

Port of Long Beach:[94] The Port of Long Beach makes major capital investments each year, which include environmental infrastructure projects to improve air and water quality, clean soil and underwater sediment, protect wildlife and to create a sustainable Port. Also, the capital projects improve the efficiency of the Port's shipping facilities. Major projects include:

> **Gerald Desmond Bridge Replacement:** Replacement or rehabilitation of the existing Gerald Desmond Bridge and adjacent roadway improvements.[95]
>
> **Middle Harbor Redevelopment Project:** Expansion of an existing marine container terminal. The project consolidates two existing container terminals into one 345-acre terminal. Construction includes approximately 54 acres of landfill, dredging, and wharf construction; construction of an on-dock railyard; and reconstruction of terminal operations buildings.[96]
>
> **Pier G modernization:** A multi-year, $980 million renovation of the ITS container terminal. Construction of a new terminal administration and operations complex, new maintenance and repair facility, and a new on-dock railyard is underway as of early 2011. Shore power facilities and additional dock space are also being added.[97]

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[90] City of Commerce, *2020 General Plan*, January 2008.
[91] City of Carson, *General Plan: Final Environmental Impact Report,* October 2002.
[92] http://www.lbds.info/planning/advance_planning/lb_2030/default.asp. Web archive, May 5, 2011.
[93] http://www.lbds.info/planning/advance_planning/general_plan.asp. Web archive, May 5, 2011.
[94] http://www.polb.com/about/projects/default.asp. Web archive, March 16, 2011.
[95] Port of Long Beach, *Gerald Desmond Bridge Replacement Project: Final Environmental Impact Report / Environmental Assessment & Application Summary Report*, July 2010, p. ES-5.
[96] Port of Long Beach, *Middle Harbor Redevelopment Project Final EIR*, Chapter 1, April 2009.
[97] http://www.polb.com/about/projects/default.asp. Web archive, March 16, 2011.

Long Beach Harbor Dredging: U.S. Army Corps of Engineers and the Port have commenced a $40 million dredging project to aid navigation in and around the Port, safely contain contaminated sediments and recycle the dredge material as fill in the Pier G modernization project.[98]

Pier S Marine Terminal: Development of a 150-acre container terminal on Pier S and construction of navigational safety improvements to the Back Channel.[99]

Pier B Rail Yard Expansion: Expansion of the existing Pier B Rail Yard in two phases, including realignment of the adjacent Pier B Street and utility relocation.[100]

I-710 Corridor Project: The Long Beach Freeway (I-710) is a vital transportation artery, linking the Port of Long Beach to the rest of Southern California and beyond. The Los Angeles County Metropolitan Transportation Authority (Metro) is heading a regional effort to study the potential environmental impacts of improvement projects on the corridor.[101] The Port of Long Beach is one of several agencies funding the study.[102]

C. Analysis

1. Aesthetics

The City of San Bernardino General Plan EIR (2005-2025) lists noise, transportation and traffic impacts – not aesthetics – as remaining significant, unavoidable, and adverse at build out after mitigation measures are applied.[103]

The City of Commerce General Plan[104] does not include a discussion of cumulative impacts from existing or ongoing projects. There are two existing projects listed on the City of Commerce website within five miles of the railyards as of April 29, 2011: a Gold's Gym building at 2035 Camfield Avenue and a warehouse development at 6600 Bandini Boulevard, both with an initial study and a mitigated negative declaration.[105,106] The initial studies and mitigated negative declarations found that approval and subsequent implementation of the proposed Gold's Gym building and the proposed warehouse

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[98] City of Long Beach, *Harbor Department Transfer Analysis*, June 2010, p. 20.
[99] http://www.polb.com/about/projects/default.asp. Web archive, March 16, 2011.
[100] http://www.polb.com/about/projects/default.asp. Web archive, March 16, 2011.
[101] Fact sheet, *Los Angeles County Metropolitan Transportation Authority, I-710 Corridor Project EIR/EIS.*
[102] Los Angeles County Metropolitan Transportation Authority, *I-710 South Corridor Project EIR/EIS Scope, Budget, and Schedule*, Revised - Planning and Project Committee, November 2010, p. 3.
[103] *Final San Bernardino General Plan Update and Associated Specific Plans: Environmental Impact Report*, September 2005, p. 6-1.
[104] City of Commerce, *2020 General Plan*, January 2008.
[105] City of Commerce, *Initial Study and Mitigated Negative Declaration, Gold's Gym Building*, July 2006.
[106] City of Commerce, *Final Initial Study, Xebec Bandini Boulevard Project*, July 2006.

development project will not have either individual or cumulatively considerable impacts, when considering planned and proposed development in the immediate vicinity of either project.[107,108]

Aesthetics is not listed under the cumulatively significant impacts at build out in the General Plan EIR for the City of Carson.[109] The EIR for the Port of Long Beach Gerald Desmond Bridge Replacement, found the project, in conjunction with all related projects planned within the Port, would not contribute to cumulatively considerable significant or adverse impacts on aesthetics.[110]

2. Noise

The City of San Bernardino General Plan EIR (2005-2025) identified noise impacts as remaining significant, unavoidable, and adverse at build out after mitigation measures are applied:[111] the identified significant and unavoidable noise impacts are to parklands only and are generated by projected airport noise from the San Bernardino International Airport located within the City of San Bernardino. The EIR found that, until the Airport Master Plan has been adopted by the San Bernardino International Airport Authority and corresponding noise contours have been established, the impact to parkland near the airport could exceed the limitations established by the General Plan and would be considered a significant adverse and unavoidable impact.[112]

ARB staff does not anticipate the incremental effect of potential noise impacts identified at the railyard would contribute to the identified future noise impacts to the parklands generated by the airport because the impacted parklands are not near the BNSF San Bernardino Railyard. The San Bernardino International Airport is on the east side of I-215, 4.5 miles to the east of the BNSF San Bernardino Railyard.

As noted in the discussion for Aesthetics, the City of Commerce General Plan[113] does not include a discussion of cumulative impacts from existing or ongoing projects. The two existing proposed projects within five miles of the railyards both have an initial study and a mitigated negative declaration, which found that approval and subsequent implementation of the two proposed projects will not have either individual or

[107] City of Commerce, *Initial Study and Mitigated Negative Declaration, Gold's Gym Building*, July 2006, p. 4.
[108] City of Commerce, *Final Initial Study, Xebec Bandini Boulevard Project*, July 2006, p. 4.
[109] City of Carson, *General Plan: Final Environmental Impact Report*, October 2002, p. 2-5.
[110] Port of Long Beach, *Gerald Desmond Bridge Replacement Project: Final Environmental Impact Report / Environmental Assessment & Application Summary Report*, July 2010, p. 2-376.
[111] *Final San Bernardino General Plan Update and Associated Specific Plans: Environmental Impact Report*, September 2005, p. 6-1.
[112] *Final San Bernardino General Plan Update and Associated Specific Plans: Environmental Impact Report*, September 2005, p. 5.10-37.
[113] City of Commerce, *2020 General Plan*, January 2008.

cumulatively considerable impacts when considering planned and proposed development in the immediate vicinity of either project.[114,115]

The General Plan EIR for the City of Carson identified unavoidable significant impacts related to mobile source noise at build out. Although mitigation measures related to mobile source noise would be implemented on a project-by-project basis, it is anticipated that these impacts would remain significant and unavoidable.[116]

3. Transportation and Traffic

The City of San Bernardino General Plan EIR identified cumulative impacts on several freeway segments at build out that were considered significant and unavoidable because improvements to the freeway system are the responsibility of the existing regional transportation agencies, not the City of San Bernardino.[117]

Staff does not anticipate that the proposed project's potential for traffic impacts on arterial streets in the vicinity of the railyard (caused by a potential shift in a gate location) would contribute incrementally to cumulative traffic impacts on the freeway system identified in the City of San Bernardino General Plan EIR because a change in a gate location would not affect the volume of truck traffic on the freeways.

As noted in the discussion for Aesthetics, the City of Commerce General Plan[118] does not include a discussion of cumulative impacts from existing or ongoing projects. The two existing proposed projects within five miles of the railyards both have an initial study and a mitigated negative declaration, which found that approval and subsequent implementation of the two proposed projects will not have either individual or cumulatively considerable impacts when considering planned and proposed development in the immediate vicinity of either project.[119,120]

Adverse cumulative impacts to transportation and traffic have been identified for the Port of Long Beach projects, improvements to SR-47, widening of I-710 north of the Ports of Los Angeles and Long Beach (i.e., the I-710 Corridor Project), and the SR-47 connector ramp.[121] The City of Carson General Plan EIR also identified unavoidable significant impacts related to the increase in traffic volumes within the City for the planning horizon year of 2020. The General Plan EIR identified an additional 14

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[116] City of Carson, *General Plan: Final Environmental Impact Report,* October 2002, p. 8-2.
[117] *Final San Bernardino General Plan Update and Associated Specific Plans: Environmental Impact Report*, September 2005, p. 5.14-44.
[118] City of Commerce, *2020 General Plan*, January 2008.
[119] City of Commerce, *Initial Study and Mitigated Negative Declaration, Gold's Gym Building*, July 2006, p. 4.
[120] City of Commerce, *Final Initial Study, Xebec Bandini Boulevard Project*, July 2006, p. 4.
[121] Port of Long Beach, *Gerald Desmond Bridge Replacement Project: Final Environmental Impact Report / Environmental Assessment & Application Summary Report*, July 2010, p. 2-383.

roadway segments operating at unacceptable service levels over existing conditions,[122] three of which are within a mile of the UP ICTF/Dolores Railyards.[123] In addition, development under the General Plan would create unavoidable significant impacts relating to the exceedance of level of service standards established by the congestion management plan at Carson freeway monitoring stations. Although mitigation measures would be implemented on a project-by-project basis, it is anticipated that these impacts may remain significant and unavoidable.[124]

4. Conclusion

a. Aesthetics

Based on ARB's review of the related projects and projected development in the area of the railyards listed above, staff does not anticipate the incremental effect or impact of the identified potential light impacts at the railyards, when added or combined with adopted projections within the area and other recent and future closely related projects, to be cumulatively considerable, because any potential light changes would occur in an area already dominated by industrial lighting such that any changes would likely be unnoticeable. However, because it is unknown what lighting changes may be undertaken and what development may occur in the area of the railyards that could combine with the railyards' potential light impacts (see Chapter IV, Section C.1.b. *Aesthetics, Impacts Analysis*), this analysis takes a conservative approach and considers the cumulative impact to light to be potentially significant. As explained in Chapter IV, Section C.1.c. (*Aesthetics, Potential Mitigation*) ARB cannot identify feasible mitigation for potential light and glare impacts, so this potential cumulative light impact remains significant and unavoidable.

b. Noise

Based on ARB's review of the development in the area of the railyards listed above, staff does not anticipate the incremental effect or impact of potential noise impacts of the proposed project, when added or combined with adopted projections within the area and other recent and future closely related projects, to be cumulatively considerable. Any potential noise impacts at the railyards would be the result of a movement of operations from one location to another on the railyard sites, without increasing the existing overall noise levels at the railyards (see Chapter IV, Section C.2.c. *Noise, Impacts Analysis*). The potential for noise impacts from the proposed project, when considered in combination with other plans and projects in the vicinity, is not expected to result in cumulative noise impacts, because the potential impacts from operational

[122] City of Carson, *General Plan: Final Environmental Impact Report,* October 2002, pp. 4.3-36, 4.3-45.
[123] UP is already considering a gate change at the UP ICTF/Dolores facility now as part of the ICTF Modernization Plan. The UP ICTF Modernization Plan includes a proposal to move the main gate from Sepulveda to Anaheim Street to serve as the truck entrance to the ICTF. The UP ICTF Modernization Plan is currently being reviewed under an Environmental Impact Report being prepared by the South Coast Air Quality Management District.
[124] City of Carson, *General Plan: Final Environmental Impact Report,* October 2002, p. 8-1.

changes would likely be unnoticeable in the industrial environment of the sites within existing noise conditions, and because potential cumulative projects are too remote from the proposed project sites to combine with the project's potential impacts for purposes of cumulative noise impacts.

However, because it is unknown at this time what potential noise impacts may arise from any operational changes that may be undertaken, and it is unknown what development may occur in the vicinity of the railyards that could combine with the railyard's potential noise impacts, this analysis takes a conservative approach and considers the cumulative impact to noise to be potentially significant. As explained in Chapter IV, Section C.2.d. (*Noise, Potential Mitigation*), ARB cannot identify feasible mitigation for potential cumulative noise impacts, so this impact remains significant and unavoidable.

c. Transportation and Traffic

Based on ARB's review of the development in the area of the railyards listed above, staff does not anticipate the incremental effect or impact of potential traffic impacts from a shift in operations at the railyards, when added or combined with adopted projections within the area and other recent and foreseeable future closely related projects, to be cumulatively considerable, because potential traffic impacts from a movement in a gate location would be only to arterial streets in the vicinity of the railyards (see Chapter IV, Section C.3.b. *Traffic, Impacts Analysis*). Potential impacts to arterial streets in the vicinity of the railyards are not expected to contribute to identified cumulative impacts on freeway systems because the Revised 2010 Commitments will not change the operational level of the railyards, and therefore will not add new truck trips to the identified impacted freeway segments. However, because it is unknown at this time what development may occur in the vicinity of the railyards that could combine with the railyard's potential traffic impacts to arterial streets, this analysis takes a conservative approach and considers the cumulative impact to traffic on the arterial streets in the vicinity of the four railyards to be potentially significant. As explained in Chapter IV, Section C.3.c. (*Traffic, Potential Mitigation*), ARB cannot identify feasible mitigation for potential cumulative traffic impacts, so this impact remains significant and unavoidable.

VI. ALTERNATIVES ANALYSIS

A. Introduction

1. CEQA Requirements

This chapter provides a discussion of alternatives to the proposed project as required by CEQA. An EIR must describe a range of reasonable alternatives to the proposed project that would feasibly attain most of the project objectives and provide a means for evaluating the comparative merits of each alternative. A "No Project" alternative must also be evaluated. The range of alternatives must be sufficient to permit a reasoned choice, but need not include every conceivable project alternative. CEQA Guidelines §15126.6(a) indicate that there is no ironclad rule governing the nature or scope of the alternatives to be discussed other than the rule of reason. The key issue is whether the selection and discussion of alternatives fosters informed decision making and meaningful public participation.

The regulation that implements the ARB's certified regulatory program does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an EIR under CEQA.

The purpose of the alternatives analysis is to determine whether or not a variation of the proposed project would reduce or eliminate significant project impacts, within the basic framework of the basic project objectives. Alternatives considered in an environmental document should be feasible and should attain basic project objectives. The primary objective of the Revised 2010 Commitments is to further reduce diesel PM emissions at the four identified high-priority railyards beyond the levels expected under the existing program of adopted regulations and agreements, and specifically to achieve at least an 85 percent reduction in diesel PM emissions between 2005 and 2020 regardless of growth in activity or operations.

An agency "need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative." (CEQA Guidelines §15126.6 (f)(3)). The analysis should focus on alternatives that are potentially feasible and that take economic, environmental, social, and technological factors into account, and should focus on reducing or avoiding significant environmental impacts associated with the proposed project. Alternatives that are unreasonable, infeasible, remote, or speculative may be identified, but their potential environmental impacts are not evaluated in this document.

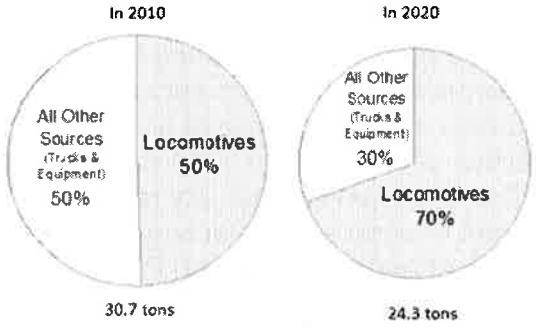
2. Context for Regulatory Versus Voluntary Approaches

Much of the discussion of alternatives in this document (both feasible and infeasible alternatives) revolves around the merits of ARB pursuing a regulatory approach versus a voluntary approach that relies on an enforceable agreement negotiated with the railroads. The following facts provide the context for the discussion in this chapter.

- ARB has already effectively regulated all of the diesel PM emission sources at a railyard under its direct authority[125] (e.g., trucks, cargo handling equipment, transportation refrigeration units, locomotive fuels, etc.). As a result, emissions from these sources will continue to decline into the future. The key element of these ARB regulations requires owners of existing diesel vehicles/equipment to reduce diesel PM emissions from those vehicles/equipment by either installing ("retrofitting") add-on pollution control devices called filters to capture the diesel PM in the engine exhaust or replacing those existing vehicles/equipment on a defined, accelerated schedule with new models that have built-in PM filters. These filters reduce diesel PM emissions by at least 85 percent on day one of operation.

- Locomotives are the largest source of diesel PM emissions at the railyards, contributing roughly half the emissions from the four yards combined in 2010, and growing to more than two-thirds of all the remaining emissions by 2020 as the other sources are increasingly well-controlled. Any effective mechanism to further reduce diesel PM emissions at the four railyards (beyond the existing program of adopted regulations and agreements) must result in significant new reductions from locomotives.

Figure F-8
Diesel PM Emissions with Existing Program Only at All Four Priority Railyards Combined



But at the four priority railyards, ARB field surveys indicate that all of the locomotives in routine operation are locomotives that California is specifically preempted from regulating under the federal Clean Air Act. Only the U.S. EPA can regulate the emissions from these locomotives.

- U.S. EPA regulations require that new locomotives and engines achieve 85 percent or better control of PM emissions, starting with new models of locomotives and engines manufactured in 2015. However, these federal regulations do not require railroads to retrofit PM filters on their fleets of existing locomotives or to accelerate the replacement of those locomotives with models achieving the 85 percent PM control. Based on the railroads' historic rate of locomotive replacement and

[125] ARB's authority to regulate non-preempted locomotives is discussed in Chapter III, Existing Setting.

remanufacture of the engines, U.S. EPA's rulemaking documents indicate that the entire national fleet will not meet the 85 percent PM control level until after 2035.[126]

- The railroads voluntarily entered into an enforceable 1998 Agreement with ARB that established an emissions performance standard that effectively accelerated the introduction of cleaner switch and interstate line haul locomotives into the fleet operating in the South Coast Air Basin by 2010. The 67 percent reduction in NOx emissions being achieved under this Agreement is based on a performance standard that lets the each railroad chose the specific strategy for cleaner locomotives that best fits its business needs. The railroads also voluntarily entered into an enforceable 2005 Agreement with ARB to reduce locomotive idling, use cleaner fuels in interstate locomotives, allow railyard inspections, and provide emission inventories/health risk assessments for 17 major railyards in the State. These agreements are successfully reducing diesel PM and NOx emissions from UP and BNSF locomotives in California, well beyond the benefits of the applicable federal emission standards for locomotives. The railroads are in full compliance with both agreements.

B. Alternatives Considered but Rejected as Infeasible and Not Analyzed

A CEQA document should identify any alternatives that were considered by the lead agency, but were rejected as infeasible during the scoping process and briefly explain the reasons underlying the lead agency's determination (CEQA Guidelines §15126.6(c)). While the scope and goals of proposed projects may be relatively specific, a variety of options can be considered as alternatives to the proposed project.

1. Background

Community groups and the South Coast Air Quality Management District (District) have advocated a wide variety of approaches that they believe ARB should pursue, including an extensive list of recommendations submitted on April 24, 2008. ARB responded to that list by preparing a detailed 300 plus-page technical evaluation of the feasibility of 37 options, focusing on ARB's legal authority to implement the respective options, the ability of each option to reduce diesel PM emissions, and the related cost-effectiveness of each option.[127] Staff drew from that technical evaluation in the summary below of the alternatives considered but rejected as infeasible and not analyzed for their potential environmental impacts in this document.

These alternatives have been eliminated from further detailed consideration in this document for the following reasons: 1) they fail to meet most of the basic project objectives, 2) they are infeasible as defined by CEQA (CEQA Guidelines §15364), or 3) they are unable to avoid significant impacts (CEQA Guidelines §15126.6(c)).

[126] U.S. EPA Fact Sheet, *Emission Factors for Locomotives*, April 2009, p. 8.
[127] *Technical Options Document*, August 2009.

2. ARB Regulation for Preempted Locomotives

Stakeholders have urged ARB to adopt a statewide regulation for all locomotives (preempted and non-preempted) that requires the railroads to install diesel PM filters in the near-term, and accelerate the introduction of locomotives meeting U.S. EPA's most stringent Tier 4 emission standards to achieve a 100 percent Tier 4 fleet in California by 2020. As discussed extensively in Appendix A of the *Recommendations Document*, the federal CAA preempts ARB from regulating emissions from the vast majority of the locomotives operating in California. While regulation is infeasible, UP and BNSF have agreed to meet and confer with ARB in 2013 regarding the progress being made by locomotive manufacturers to produce Tier 4 interstate line haul locomotives and the potential for interstate testing of prototype locomotives to include California.

Alternative B presented later in this chapter discusses the potential benefits and impacts of an ARB regulation limited to the older, non-preempted locomotives within the agency's authority.

3. ARB Regulation to Limit Locomotive Idling or Control Locomotive Maintenance Idling Emissions

a. Locomotive Idling Limits

Stakeholders have proposed that ARB adopt a statewide version of the South Coast Air Quality Management District's (District) Rules 3501-3503 that sought to establish idling limits for locomotives, plus recordkeeping and air quality modeling requirements for railroads. Adopting an ARB regulation based on the District's rules would not achieve the primary project objective to further reduce emissions beyond the existing program of adopted regulations and agreements because the railroads are already implementing the requirements contained in the 2005 ARB/Railroad Agreement for all 18 major railyards that accomplish the same purpose.

From June 2005 to 2008, UP and BNSF fully implemented the key provisions of the 2005 Agreement to retrofit 99 percent or greater of California intrastate locomotives with idle reduction devices and to program the idle reduction devices to limit non-essential idling to 15 minutes. Non-essential idling excludes idling that occurs in "blue flag" maintenance areas, or is necessary to maintain locomotive engine temperature, battery voltage, air brake pressure, and other necessary operations. The current impact of the 2005 Agreement requirements for idle reduction devices, and the widespread installation of those devices, is to limit non-essential idling to 15 minutes, consistent with the District rule.

b. Control of Locomotive Idling During Maintenance Operations

Stakeholders have also proposed that ARB adopt a regulation that would require the capture and control of locomotive emissions while idling during maintenance. The intent would be to require UP to install a prototype technology (known as a "hood" or "bonnet" stationary collection system) at the UP Commerce facility, which has significant locomotive maintenance operations and emissions.

Locomotive maintenance facility idling emissions are primarily the result of technicians trouble-shooting repairs and performing federally required maintenance on locomotives. Technicians need to have the locomotives run through all of the engine power settings to ensure that the diagnostics, repairs, and maintenance were successful. Locomotive maintenance is critical to ensure the reliability, durability, and safety of locomotives while operating in railyards and on the main-lines. Maintenance idling emissions are considered "essential-idling" as they are part of federally required maintenance operations. Under federal law, these maintenance activities are performed inside what are referred to as designated "blue flag" areas. Federal law dictates that the maintenance be performed under a prescribed regulatory schedule. The maintenance is required for railroads to be able to conduct their operations.

ARB staff evaluated the technical feasibility and cost-effectiveness of advanced locomotive emission control systems (ALECS), also known as a hood or bonnet, for stationary locomotives operating within railyards. Based on limited prototype testing performed at the UP Roseville Railyard, this approach was determined to be technically feasible for stationary locomotives. ALECS has not been subject to full-scale railyard demonstration testing. Full-scale railyard demonstration testing is needed to determine the potential utilization rates and emissions reductions within actual railyard operations. Another reason for the demonstration testing is to determine what effects, if any, the ALECS system would have on the timeliness and effectiveness of railyard operations (i.e., moving locomotives in and out of the railyard). A full-scale demonstration is also needed to assess ALECS multiple bonnet system options to determine which can best be utilized between the locomotives and the stationary control equipment. At the present time, a full-scale demonstration project is contemplated for the UP Roseville Railyard, but has not been scheduled.[128]

At this point, this type of technology needs to be subject to a comprehensive field demonstration under actual and continuous railyard operations. ARB staff indicated that the stationary collection system could potentially be cost-effective in future years, but at this time there were a number of more cost-effective strategies (e.g., diesel particulate filters on locomotives) to reduce locomotive emissions and associated public health risks.[129]

[128] *Technical Options Document*, August 2009, p. 106.
[129] *Technical Options Document*, August 2009, p. 108.

ARB staff found this approach to be infeasible under CEQA because this technology is not currently available or proven for actual railyard operations. Current analyses have not demonstrated that the technology is cost-effective and implementation could impact railroad operations, potentially triggering a conflict with the ICCTA. However, the Revised 2010 Commitments would require UP to specifically evaluate the potential benefits and issues with use of the hood technology at the UP Commerce Railyard and the UP ICTF/Dolores Railyards. UP could elect to purchase and install this technology to help meet the emissions performance standard under the Revised 2010 Commitments.

4. ARB Actions to Determine Compliance with U.S. EPA Locomotive Emission Standards

Stakeholders have proposed two approaches – a California locomotive in-use testing program and a remote sensing program – for ARB to determine whether locomotives are complying with the applicable U.S. EPA emission standards. Under both proposed approaches, if ARB identified a locomotive that exceeded the federal emission standards, it would be up to U.S. EPA to take any enforcement action. Both of the suggested approaches for ARB action are infeasible for different reasons. Neither would attain the primary project objectives because there is no assurance of emission reductions beyond the existing federal regulations and no protection against rising emissions that could result from growth in cargo or railyard activity.

a. California Testing of Existing ("In-Use") Locomotives

California and other states are preempted from requiring in-use testing of locomotives under U.S. EPA regulation at 40 CFR, Part 85, §85.1603(a)(2). Even if ARB could require the railroads to pull locomotives out of service to undergo emissions testing to determine compliance with U.S. EPA locomotive emission standards, it would be cost prohibitive to set up a separate program in California that would essentially duplicate the existing U.S. EPA program and achieve very little potential benefit based on the high rate of compliance determined by U.S. EPA under its own testing program.

U.S. EPA prescribes a percentage of in-use locomotives that are tested annually by independent emission testing facilities. Since the inception of the program in 2005, no locomotives that have been tested to date have exceeded the U.S. EPA emission standards. The U.S. EPA locomotive emission standards are required to "not be exceeded" during the locomotive's useful life. To avoid non-compliance and a possible national locomotive fleet recall, locomotive manufacturers build locomotives with a significant compliance margin below emission standards.

This approach is infeasible for ARB based on cost and would not achieve the basic project objective.

b. California Remote Sensing Program

Remote sensing technology has the potential to measure locomotive emissions during normal operations as a locomotive passes a fixed point. However, the results of a pilot program required by State legislation showed that locomotive remote sensing technologies cannot accurately and repeatedly determine whether a locomotive is above or below the applicable federal emission standards.[130]

This approach is infeasible because the technology cannot perform reliably and the approach would not meet the basic project objective for the reasons described above.

5. Voluntary Commitments with Prescriptive Requirements

Stakeholders have suggested that if ARB pursues the voluntary commitment approach, the commitments should prescribe a list of specific actions that the railroads will take to: upgrade the locomotive fleet to the cleanest Tier 4 standards, electrify cargo handling equipment at the railyards, install a hood or bonnet system to capture and control locomotive maintenance idling emissions at UP Commerce, and implement identified other actions to reduce or mitigate the impacts of existing railroad operations on neighboring residents.

A partial list of the other actions suggested by stakeholders includes:

- Install walls that can reduce noise pollution and enforce noise regulations.
- Plant trees and install walls between the railyard and the community to serve as air pollution buffers.
- Weatherize and retrofit homes to prevent air pollution from entering.
- Install air conditioning units with filters in structures like homes and school day care centers.
- Install dual pane and tinted windows to protect from light and noise pollution.
- Fund a health clinic in the community.
- Fund a medical mapping study of the community.
- Fund community recreation centers.
- Move emissions sources (like truck gates and maintenance facilities) to another location within the railyard that is further away from nearby residents.
- Install ambient monitors to measure individual railyard diesel PM emissions.

Currently, there is no approved specific measurement technique to directly monitor or measure site-specific and source-specific diesel PM emissions. Under the Revised 2010 Commitments, ARB will work with the South Coast Air Quality Management District to install and operate two new ambient air quality monitors in the community near the BNSF San Bernardino Railyard and in the community near the BNSF Hobart

[130] Air Resources Board, *Feasibility of Using Remote Sensing Devices to Measure Locomotive Emissions: Report to the California Legislature*, December 2010.

and UP Commerce Railyards. Other than this air quality monitoring, the other actions are not within ARB's authority to require or within ARB's budget to fund. In addition, the railroads have repeatedly stated that they will not participate in an agreement that directs or potentially constrains how they may conduct their operations. They also will not participate in a prescriptive agreement that defines exactly how they must reduce diesel PM emissions. Since there is no project without the voluntary participation of the railroads, this approach is infeasible.

However, for informational purposes, ARB staff provides the following description of activities underway to address some of the actions proposed by stakeholders.

Tree planting. In 2010, BNSF provided a grant to the City of San Bernardino for $250,000. The grant will be used to construct a median and to plant landscaping with trees along Fourth Street next to the BNSF San Bernardino Railyard. The Fourth Street improvements will occur along the northwestern boundary of the BNSF San Bernardino Railyard – west of the bridge and continuing west of the truck gate.

Air filters in schools. The Center for Community Action and Environmental Justice was recently awarded a $1 million grant, through a Unocal settlement fund to install air filtration systems at seven schools located near the BNSF San Bernardino Railyard and the Union Pacific Mira Loma Railyard.

Railyard emissions. In a project agreement between British Petroleum and the University of California Los Angeles, a two-year study of railyard emissions was funded through a settlement agreement administered by the South Coast Air Quality Management District beginning in Summer 2009. The project collects filter and vapor samples in communities (i.e., Commerce, San Bernardino, Long Beach) near the four high-priority railyards. The sampling sites are selected with input from members of the nearby communities.

Health effects associated with BNSF San Bernardino Railyard emissions. Loma Linda University has been awarded funds of about $860,000 from the South Coast Air Quality Management District to study the health effects on residents living near the BNSF San Bernardino Railyard. Community members trained in health research practices, in collaboration with researchers, will collect primary data through household- and school-based surveys on the prevalence of cardiovascular disease, respiratory disease, respiratory symptoms, and biologic outcomes, including lung function and airway inflammation. Researchers will also analyze secondary data from the California Cancer Registry to determine whether there is an excess of new and fatal cancers observed from 1999–2008 that could be attributed to diesel smoke and other airborne emissions. As part of the study, Loma Linda also will provide medical treatment to residents affected by the emissions.

6. Voluntary Commitments with Performance Targets for All 18 Major Railyards

Stakeholders have also suggested that if ARB pursues the voluntary commitment approach with its performance target of 85 percent emission reduction by 2020, any commitments should apply to all 18 major railyards covered by ARB's prior health risk assessments. To the extent that implementing the Revised 2010 Commitments at the four high-priority railyards has the potential to result in adverse impacts on aesthetics, noise, and traffic, extending the Commitments to 18 railyards could potentially extend the geographic scope of those impacts.

UP and BNSF have indicated they are willing and able to allocate the necessary resources on upgrades to achieve an 85 percent reduction in diesel PM emissions at the four high-priority railyards, with the understanding that there will be spillover benefits at other railyards from the cleaner locomotives introduced to meet the emission reduction targets at the four high-priority railyards. The railroads noted that implementing a project similar to the Revised 2010 Commitments at all of the 18 major UP and BNSF railyards would exceed the railroads' available capital and staff resources, and they would not be able to implement such a comprehensive project between 2010 and 2020.

Since there is no project without the voluntary participation of the railroads, this approach is infeasible.

C. Alternative A: No Project

CEQA requires a specific alternative of "No Project" to be evaluated. The No Project alternative can help define a future scenario that serves as a point of comparison for cumulative impact contributions of a project. CEQA documents typically assume that the adoption of a "no project" alternative would result in no further action by the project proponent or lead agency.

A "No Project" alternative, in this case, would be for ARB and UP and BNSF to not sign and implement the 2010 Railyard Commitments. The No Project alternative would mean the continued implementation of existing U.S. EPA and ARB regulations and agreements from 2005 to 2020. As shown in Tables F-3 through F-6 in Chapter IV, ARB staff estimates that UP and BNSF will reduce diesel PM emissions at the four priority railyards under the existing program by 50-75 percent by 2020, compared to 2005 levels. The level of control could be less if growth in cargo activity is high. In contrast, the Revised 2010 Commitments would require UP and BNSF to reduce diesel PM emissions at the four high-priority railyards 85 percent by 2020, compared to 2005 levels, regardless of the growth in cargo activity.

The No Project alternative, while not inducing operational shifts that could lead to identified impacts, will not get the benefits of the reduction in health risks and is

therefore not the preferred alternative. This alternative does not even partially satisfy the project objective. The No Project alternative would prolong higher diesel PM emissions and associated health risks for residents living near the four high-priority railyards.

D. Other Project Alternatives Analyzed

ARB staff evaluated the benefits and impacts of three regulatory alternatives that could (individually and cumulatively) achieve a portion of the project objective to reduce railyard diesel PM emissions and that ARB has the legal authority to implement.

- Alternative B: ARB regulation for non-preempted freight locomotives.
- Alternative C: ARB regulation requiring zero-emission cargo handling equipment operating at intermodal railyards.
- Alternative D: ARB regulation requiring railroads to prepare risk reduction audits, plans, and measures.

In the following pages, ARB staff discusses each of these alternatives including an evaluation of the feasibility, the potential beneficial and adverse environmental impacts, and the staff's conclusion as to whether the alternative can satisfy the project objective with fewer adverse environmental impacts.

1. Alternative B: ARB Regulation for Non-Preempted Locomotives

a. Description of Project Alternative

Under this alternative, ARB would adopt a statewide regulation requiring at least the major Class I railroads (BNSF and UP) to replace, retrofit, or upgrade any non-preempted locomotives operating in California to achieve more stringent California emission standards. For the regulation to take effect, ARB would need to obtain authorization from U.S. EPA to enforce the regulation under CAA §209(e)(2).

Those locomotives and locomotive engines that are not preempted include those that were manufactured prior to 1973 and have not been upgraded (remanufactured) after 2000, and all locomotives that have exceeded 133 percent of their useful life since original manufacture or remanufacture, whichever is later.

b. Evaluation of Feasibility

In this chapter, ARB staff has framed the evaluation with a series of questions and answers to discuss the basis for the conclusions.

i. What locomotives could potentially be regulated by ARB?

A detailed discussion of ARB's authority to regulate locomotives is set forth in Appendix A of the *Recommendations Document* and summarized in Chapter III. Although the Health and Safety Code vests ARB with authority to regulate locomotives,[131] that authority is circumscribed by constraints imposed by the preemptions of State regulation under the CAA and the ICCTA. CAA section 209(e)(1) preempts all states, including California, from adopting emission standards and other requirements related to the control of emissions from new locomotives. For purposes of preemption, U.S. EPA has interpreted new as it applies to locomotives to mean original manufacture and subsequent remanufacture of the locomotive[132] and that preemption applies for 133 percent of the new locomotive's useful life.[133] U.S. EPA also determined that a locomotive or locomotive engine owned by a Class I railroad would not be considered either new or preempted if it was manufactured prior to January 1, 1973 and has not been upgraded (remanufactured) to Tier 0 or higher emissions standards after January 1, 2000.[134]

To the extent that ARB has authority under the CAA to adopt emission standards for locomotives manufactured prior to 1973 and non-new locomotives that have exceeded 133 percent of their useful lives, and, once adopted, has received authorization from U.S. EPA under section 209(e)(2) to enforce the regulation, the regulation must be harmonized with the purposes and intent of the ICCTA preemption.[135]

Currently, the U.S. EPA useful life definition would generally exclude states from regulating all newer 2000 to 2011 model year locomotives because these locomotives would not typically have exceeded their useful lives by 133 percent. All of these newer locomotives were built to meet the new U.S. EPA locomotive Tier 0, Tier 1, and Tier 2 emission standards. Table F-2 in Chapter III shows the model years and emission standards for each tier of U.S. EPA locomotive emission standards.

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[131] Health and Safety Code §39666 and 43013(b).
[132] Title 40 Code of Federal Regulation (CFR) §92.2.
[133] Title 40 CFR §1074.12(b).
[134] Title 40 CFR § 92.1.
[135] *AAR v. SCAQMD, supra,* 622 F.3d 1094, 1098. Although the Court said the federally-approved regulation must be harmonized with the ICCTA preemption, it did not give any guidance on how this should be done. Based on other court and Surface Transportation Board decisions, application of the ICCTA preemption is a factually-based question. See, e.g., *Jackson, supra*, 500 F.3d 238, 253; *Bos. & Me. Corp.*, 2001 WL 458685, at *6. Thus, ARB believes that harmonization would likely entail some form of balancing the health and welfare benefits derived from regulating locomotives not preempted under the CAA against the potential burdens imposed by the regulation on the railroads' ability to manage and govern rail transportation.

ARB's regulatory authority under the CAA, once harmonized with the ICCTA preemption, would likely only apply to a limited number of switch and medium horsepower locomotives that operate within the four high-priority railyards or the South Coast Air Basin. For practical purposes, because of the decades typically required for these locomotives to reach the 133 percent of their useful life benchmark, a switch or medium horsepower locomotive that is not preempted by the CAA or ICCTA is likely to be a pre-Tier 0 locomotive. Line haul locomotives used to move freight between states would arguably be excluded from ARB's authority because of ICCTA considerations.

ii. How many non-preempted switch and medium horsepower locomotives could be captured by an ARB regulation?

Based on an April 2011 submittal to ARB and ARB staff's independent field surveys, UP and BNSF operated on a regular basis approximately 80 arguably non-preempted and pre-Tier 0 locomotives in California in 2010 (45 switch and 35 medium horsepower). Recent ARB field surveys indicate that these arguably non-preempted locomotives are not operating at any of the four high-priority railyards on a regular basis. About 20 of the non-preempted locomotives (5 switch and 15 medium horsepower) are operating on a regular basis within the South Coast Air Basin at other railyards, and an additional 60 (40 switch and 20 medium horsepower) are operating in the rest of the State.

Between 2007 and April 2011, UP and BNSF replaced or signed grant contracts to replace nearly all of the older switch locomotives that have operated on a regular basis in the four high-priority railyards with advanced technology locomotives.

UP operates 71 of these advanced technology units in the South Coast Air Basin. UP Commerce and UP ICTF/Dolores Railyards have been fully supported by the advanced technology units since 2008. UP has about 20 arguably non-preempted switch and medium horsepower locomotives currently remaining and operating on a regular basis within the South Coast Air Basin.

In 2010, BNSF procured 11 advanced technology switch locomotives, with another 12 to be purchased in the next few years under incentive contracts. At that point, BNSF will be able to fully support both BNSF San Bernardino and BNSF Hobart Railyards with nearly all advanced technology units. By 2009, BNSF had replaced all of its older, arguably non-preempted switch and medium horsepower locomotives in the South Coast Air Basin with models remanufactured to U.S. EPA Tier 0 emission standards, restarting their useful lives for the purpose of determining preemption under the CAA. As a result, BNSF currently has no non-preempted switch or medium horsepower locomotives operating within the South Coast Air Basin on a regular basis.

iii. Would all of the arguably non-preempted switch and medium horsepower locomotives have to be upgraded under an ARB regulation?

Not necessarily. Railroads could remove locomotives from the scope of the regulation by (1) converting an arguably non-preempted locomotive to a preempted locomotive by remanufacturing it to meet the minimum U.S. EPA Tier 0+ emission standard or (2) removing the older locomotive from California service and replacing it with a preempted locomotive (i.e., Tier 0 or Tier 0+) from another state.

Railroads also may contest the presumption that California has clear authority to regulate what it has determined to be non-preempted locomotives. The railroads have indicated that there are no non-preempted locomotives that operate solely within California. Rather, the railroads indicate that older switch and medium horsepower locomotives that are not preempted under the CAA move regularly between regions and states, as part of a dynamic western region pool of locomotives and arguably are preempted under the ICCTA. UP and BNSF's western region primarily includes the States of California, Arizona, New Mexico, Nevada, and Oregon. As a result, the railroads could challenge a State non-preempted locomotive regulation as being preempted under ICCTA, as the railroads may argue that an ARB non-preempted locomotive regulation adversely impacts interstate commerce and unreasonably burdens management and governance of rail transportation. Litigation could delay any benefits of the regulation.

iv. What are the potential emission reductions from an ARB regulation for arguably non-preempted switch and medium horsepower locomotives?

There is a range of potential emission reductions that could result from ARB adoption and implementation of such a regulation for BNSF and UP operated locomotives. On the low end, the diesel PM benefits could be zero if BNSF and UP chose to replace all of the 80 remaining pre-Tier 0 locomotives in California with federally preempted Tier 0 locomotives from other states, because there is no change in PM emission levels between those standards. If BNSF and UP remanufactured the entire California fleet of 80 pre-Tier 0 switch and medium horsepower locomotives that existed in 2010 to comply with an ARB regulation, the remanufacture would have to meet U.S. EPA Tier 0+ standards under federal law. Thus, as shown in Table F-13, the resulting benefits could be 0-16 tons of PM reductions per year statewide, with the certainty that virtually no benefits would be realized at the four high-priority railyards. For perspective, ARB estimates that all BNSF and UP locomotives statewide emitted about 1,400 tons per year of PM in 2010.

Table F-13
ARB Non-Preempted Locomotive Regulation
Estimated Diesel PM Emission Reductions from Upgrading BNSF and UP Pre-Tier 0 Switch and Medium Horsepower Locomotives to Either Tier 0 or Tier 0+
(tons per year)

Areas of California	Number of Non-Preempted Locomotives* in 2010	PM Reductions with Tier 0**	PM Reductions with Tier 0+**
South Coast Air Basin	20	0	4
Rest of State	60	0	12
Total Statewide	80	0	16

* Number of UP and BNSF non-preempted locomotives that operate within the South Coast Air Basin or the rest of the State on a regular basis, based on UP and BNSF intrastate locomotive inventories for calendar year 2010, submitted in April 2011, and cross-referenced with UP and BNSF 1998 Locomotive NOx Fleet Average Agreement data for the South Coast Air Basin in calendar year 2010.
** Based on annual diesel fuel consumption of 25,000 gallons and U.S. EPA switch duty cycle.

v. Would the current line haul locomotive fleet achieve additional emission reductions at the four priority railyards beyond the federal program by 2020 if ARB could regulate the non-preempted locomotives that exceeded their useful lives?

Likely not, because very few line haul locomotives currently operating in Southern California would be non-preempted and subject to the ARB regulation. ARB staff recognizes that such a regulation could reduce diesel PM emissions in other areas of the State (as shown on Table F-13) if the railroads chose to comply by upgrading the affected locomotives to Tier 0+ standards. ARB pursuit of such a regulation *in addition to* the Revised 2010 Commitments could sacrifice the much greater existing and planned reductions at the four priority railyards and other railyards in the South Coast Air Basin. The Revised 2010 Commitments recognize the railroads' right to withdraw from their obligations under the agreement, including their obligation to maintain emission reductions already achieved at the four priority railyards, if ARB pursues a regulatory approach, absent the railroads first having failed to comply with the terms of the Revised 2010 Commitments.

In response to the 1998 ARB/Railroad Agreement, BNSF and UP operate locomotive fleets in the South Coast that currently achieve Tier 2 average emission levels, up to twenty years ahead of the rest of the country. Tier 2 interstate line haul locomotives built between 2005 and 2011 would, in most cases, not exceed 133 percent of their

useful lives any earlier than 2013. In 2013, U.S. EPA requires the Tier 2+ remanufacturing kits for Tier 2 locomotives that are ready for remanufacture. The UP and BNSF Tier 2 interstate line haul locomotives are expensive (at about $2 million or more per unit), are higher horsepower and more fuel efficient units, and pull most of the railroads' revenue commodities. As a result, it is likely UP and BNSF would invest the necessary funding (up to $200,000 or more per unit) to remanufacture them to meet the required U.S. EPA Tier 2+ PM standards beginning in 2013.

A Tier 2+ locomotive remanufacturing could extend the federal preemption of Tier 2 locomotives for at least an additional seven to ten years. As a result, Tier 2 interstate line haul locomotives may not be eligible for an ARB non-preempted locomotive State regulation until sometime between 2020 and 2030.

c. *Potential Impacts*

i. Impact on Aesthetics

The four high-priority railyards are in continuous operation under well-lighted conditions, 24 hours a day, seven days a week. Under existing conditions, there is already substantial nighttime light and glare from fixed lighting sources. A regulation for non-preempted switch and medium horsepower locomotives would result in deployment of new or upgraded lower-emitting locomotives, which should have no impact on light and glare at any of the four high-priority railyards.

ii. Impact on Noise

The four high-priority railyards covered by the Commitments are large, existing industrial-type operations that already operate 24 hours a day, seven days a week, with on-site and entering/exiting diesel equipment. The physical scale, frequency of activity, noise, and vibration from these operations are part of the existing conditions.

A regulation for non-preempted switch and medium horsepower locomotives would result in deployment of new or upgraded lower-emitting locomotives. These lower-emitting locomotives are quieter than the current models. When the new advanced technology line haul locomotives are available, staff expects those units to be roughly 10 to 30 percent quieter than the current locomotives that will be replaced. Therefore, the noise reduction resulting from Alternative B would be a positive impact. However, in field surveys in June, July, August, and September 2010, ARB staff found no non-preempted locomotives owned by BNSF or UP in operation at any of the four high-priority railyards on a regular basis. Therefore, little or no overall railyard noise reductions would be likely to occur at any of the four high-priority railyards by remanufacturing the non-preempted switch and medium horsepower locomotives.

iii. Impact on Transportation and Traffic

Trucks enter and exit the four high-priority railyards, either through a gate complex in one area of the railyard or through entrance and exit gates in separate areas of the railyard. At each railyard, the container trucks take a freeway route on exiting. A regulation for non-preempted switch and medium horsepower locomotives could result in deployment of new or upgraded lower-emitting locomotives, which would have no impact on transportation, or on traffic, or on movement of drayage trucks.

d. Conclusion

A regulation for non-preempted switch and medium horsepower locomotives would not be expected to generate any adverse impacts on aesthetics or on transportation and traffic. New or upgraded locomotives are quieter than the current models, so the noise reduction resulting from Alternative B could generate a positive impact. However, since ARB staff field surveys in June through September 2010 found no non-preempted locomotives owned by BNSF or UP in operation at any of the four high-priority railyards on a regular basis, little or no noise reductions would be likely to occur at any of the four high-priority railyards by remanufacturing the non-preempted switch and medium horsepower locomotives.

A regulation to implement this alternative, consistent with State and federal law, would, however, not satisfy the project objectives because it would not reduce diesel PM emissions at the four high-priority railyards beyond the existing program. The statewide reductions in diesel PM would be 0-16 tons per year statewide, with no reductions realized at the four high-priority railyards. Under the Revised 2010 Commitments, 12.5 tons per year of additional diesel PM reductions would be achievable at the four high-priority railyards alone. Similarly, the Revised 2010 Commitments may result in spillover emission reductions benefits to the rest of the State, through the accelerated introduction of Tier 4 interstate line haul locomotives into California, that would equal or exceed the potential diesel PM emissions reductions statewide of an ARB non-preempted locomotive regulation.

2. Alternative C: ARB Regulation for Zero-Emission Cargo Handling Equipment

a. Description of Project Alternative

Under this alternative, ARB could consider amending the existing statewide regulation for cargo handling equipment operating at ports and intermodal railyards to require certain equipment at intermodal railyards to meet zero-emission levels on site, essentially through electrification of certain operations.

Under such a proposal, the regulation could be amended to require the replacement of nearly all of the existing diesel cargo equipment that moves containers, including

existing diesel rubber tired gantry cranes (RTGs), diesel yard tractors and forklifts/picks with electrified rail mounted gantry (RMG) cranes and the installation of the necessary RMG electric infrastructure at covered railyards. While existing diesel RTGs, yard tractors, and forklifts/picks are capable of operating anywhere in the railyard to move containers, an electric RMG is a very large overhead crane mounted on fixed guides that transfers a container between the railcar and the truck trailer and is fully capable of performing the functions of the more mobile diesel cargo handling equipment. These RMGs are installed in single, fixed location between the rail tracks and the container storage area.

Alternatively, a proposed regulation could more limitedly require replacement of diesel yard tractors with fully electric yard trucks as part of the existing yard operations.

b. Evaluation of Feasibility

ARB has the authority under State and federal law to adopt regulations to reduce emissions from mobile cargo handling equipment,[136] as evidenced by the existing ARB regulation for these sources. In general, regulations adopted by ARB must be necessary, cost-effective, and technologically feasible.[137] For regulations to control sources of air toxics like diesel PM, State law requires ARB to design the regulation based on use of the best available control technology (BACT), in consideration of risk and cost.[138]

This section discusses ARB staff's evaluation of the feasibility of going beyond the existing regulations to require zero-emission technology for these types of equipment at the four high-priority railyards. This project alternative would require the purchase of new equipment, construction of significant new electric infrastructure at the railyard, and redesign of current railyard operating practices.

In addition to meeting the aforementioned requirements for adoption of regulations under State law, ARB would be required to obtain authorization from U.S. EPA prior to ARB enforcing the regulation. ARB would also have to consider if a federally-authorized regulation could be harmonized with the ICCTA preemption.[139] In evaluating its authority to adopt amendments to the cargo handling regulation, among the criteria that the Board would consider in adopting the proposed amendments would be the emission/health risk reductions that would be achieved from the amendments and the burdens related to cost that would be imposed upon the railroads.

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[136] Health and Safety Code §39658, 39666, 39667, 43013(b), and 43018.
[137] Health and Safety Code §43013(a) and (b).
[138] Health and Safety Code §39666 and 39667.
[139] See *AAR v. SCAQMD, supra,* 622 F.3d at 1098. Although, to date, the railroads have not challenged the existing cargo handling regulation, they have stated that they have voluntarily elected to comply and have reserved their right to challenge the regulation.

In evaluating the burdens imposed by a proposed regulation, ARB staff and the Board would consider, among other things, the benefits and costs of the proposed regulation. The baseline for this analysis would be full implementation of the existing regulation, equipment that meets the required Tier 4 PM levels (85 percent or better PM control), and substantial recent investments by the railroads in the new Tier 4 equipment. As discussed below, the technology to achieve additional on-site emission reductions from electrification of cargo handling equipment presently exists for several railyard applications.

If use of electrified RMGs virtually eliminated all of the diesel cargo handling equipment emissions projected to remain in 2020, the maximum diesel PM reductions for all four railyards combined would be under 2.6 tons per year, at a cost of over $1.1 billion. For context, ARB's 2007 regulation to reduce emissions and health risk from drayage trucks serving ports and intermodal railyards (including the four priority yards) had roughly the same estimated total cost to reduce diesel PM by 949 tons per year. Alternatively, if ARB required conversion of Tier 4 diesel yard trucks to electric trucks at these four railyards, the maximum diesel PM reductions for all four railyards combined would be about 1.8 tons per year, at a minimum cost of over $56 million.

ARB staff does not anticipate that a regulatory proposal to mandate electrification of cargo handling equipment would be cost-effective at this time. The following sections discuss the basis for staff's estimates of potential emission reductions and costs associated with this alternative.

i. Existing ARB Regulation

In December 2005, ARB approved a regulation to reduce NOx and PM emissions from diesel-fueled cargo handling equipment operated at ports and intermodal railyards. Cargo handling equipment includes yard trucks/hostlers, cranes, picks, forklifts and related equipment used to handle goods moved in containers. This existing regulation establishes BACT for covered equipment and requires all equipment to have Tier 4 level PM control (85 percent control) or better by the end of 2017 or earlier. Yard trucks must meet in-use performance standards through accelerated turnover of older yard trucks to ones equipped with cleaner, on-road engines. Non-yard truck equipment must also meet BACT, which could include retrofits and/or replacement to cleaner on-road or off-road engines.

The railroads typically turn over the cargo handling equipment at these railyards more frequently than the industry-wide assumptions in the regulation. Staff estimates that all of the yard trucks operating at the four high-priority railyards could meet the Tier 4 PM level as early as 2012-2013, and all cranes, picks, and forklifts could meet the Tier 4 PM level by as early as 2015.

ii. Emissions from Cargo Handling Equipment

The projected diesel PM emissions from all cargo handling equipment at the four priority railyards under the existing ARB regulation are shown in Table F-14. By 2020, cargo handling equipment accounts for about ten percent of the diesel PM emissions at these yards. These figures include all diesel cargo handling equipment at each railyard and therefore represent the upper bound of emissions that could be eliminated on site from conversion to electric equipment.

Table F-14
Diesel PM Emissions from Cargo Handling Equipment
at the Four High-Priority Railyards
With the Existing Program
(tons per year)

Railyard	2005	2010	2015	2020
BNSF San Bernardino	3.0	1.2	0.6	0.4
BNSF Hobart	5.9	2.4	1.2	0.8
UP Commerce	4.8	3.0	1.5	0.9
UP ICTF/Dolores	4.4	1.6	1.0	0.5*
Total	18.1	8.2	4.3	2.6

* If implemented, the UP Modernization Plan would reduce to near zero emissions.

iii. Timing for Implementation

In the analysis of this alternative, staff has assumed that any new regulatory requirements would be implemented post-2015. With at least a year to develop and adopt the regulatory amendments under the Administrative Procedure Act, implementation of the regulation would then require significant modifications to the railyard infrastructure with additional time for the necessary environmental reviews and federal, State, and local permitting requirements.

Still more time would be required for construction and installation. ARB staff estimates that these additional steps would take at least four years from the time the regulation is approved to completion, putting implementation in the 2016-2017 period. This proposed schedule is based on recent experiences with the proposed UP ICTF

Modernization project and the proposed BNSF Southern California International Gateway near-dock railyard facility. This analysis assumes that electric RMGs would displace both the Tier 4 cranes and yard trucks that would already be operating in high-priority railyards by 2015.

iv. Potential Emission Reductions

Electric RMGs could replace nearly all of the existing equipment and achieve close to the combined 2.6 tons per year upper bound estimate of on-site diesel PM emission reductions indicated on Table F-14 for all four railyards.

ARB staff estimates that Tier 4 compliant yard trucks will account for about 70 percent of the expected 2020 emissions of diesel PM from cargo handling equipment shown in Table F-14. Conversion of Tier 4 yard trucks to electric models could achieve combined diesel PM reductions of roughly 1.8 tons per year for all four railyards.

The railyard-specific numbers for cargo handling equipment are shown in Appendix A of this *Supplement to the June 2010 Staff Report.*

Converting the cargo handling equipment to electric models would reduce or nearly eliminate on-site emissions of diesel PM at the four railyards, but would shift a small portion of those emissions to communities with fossil-fuel fired power plants to provide the necessary electricity. As California transitions to more renewable and zero-emission sources to generate electric power, that impact would be expected to diminish.

v. Costs to Purchase and Install New Equipment

The sections below provide the numbers that ARB staff used to estimate the railyard-specific cost of installing electric RMGs to replace Tier 4 compliant equipment. RMGs would virtually eliminate the need for other cargo handling equipment, including yard trucks, forklifts, and picks currently used to move containers on site. A less effective option would be to replace the Tier 4 compliant yard trucks with zero-emission yard trucks (presumed to be electric for this analysis).

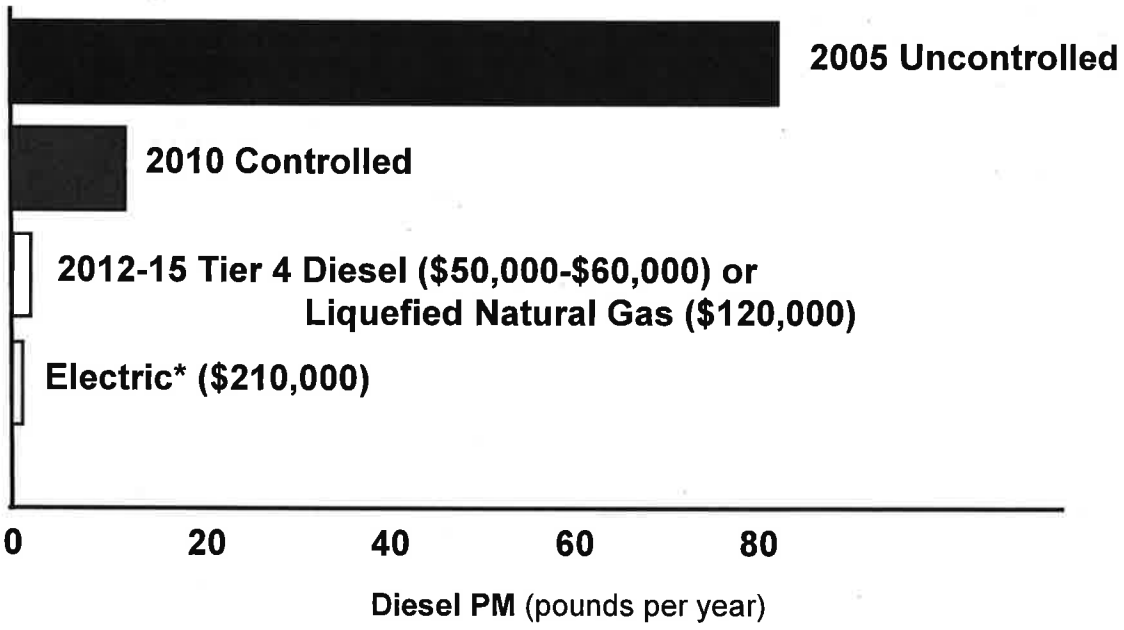
Rail-Mounted Gantry Cranes. For background, ARB staff analyzed several UP and BNSF railyards around the U.S. where the railroads have installed or are planning to install RMG cranes and the supporting electric infrastructure at existing and new facilities. To estimate the cost of purchasing and installing RMGs at the four existing high-priority yards in California, we relied on the published estimates of costs to convert the existing UP ICTF facility to electric RMG cranes as part of the UP ICTF Modernization Plan.[140]

[140] *Application for Development Project Approval, Intermodal Container Transfer Facility (ICTF) Modernization Project* (December 26, 2007).

ARB staff estimates that each railyard will need one to two RMGs for each rubber tire gantry (RTG) crane that is replaced, and may need one RMG per 50,000 to 150,000 container lifts. The cost to purchase the RMGs would be about $5 million per unit, with another $5 million per crane to install the electric infrastructure and reconfigure operations at the yards.

Electric Yard Trucks. Staff used an estimate of $210,000 per unit to purchase a new electric yard truck. There would be additional costs to install on-site electric infrastructure to charge these yard trucks. The railroads indicate that the railyard duty cycle and operations would essentially require that each existing diesel yard truck be replaced with two electric trucks to accommodate the recharging time when an electric truck would be out of service, based on current technology. Because we do not know the status of development of longer-life battery technology or quick-charge capability for electric yard trucks that might exist post-2015, ARB staff used a one-to-one replacement ratio to estimate the costs, but acknowledges the actual costs could be higher. Figure F-9 shows the relative PM emissions from yard truck technologies and costs to purchase new equipment based on operating assumptions typical of the BNSF San Bernardino Railyard.

Figure F-9
PM Emissions for a Typical Yard Truck and Per Unit Cost for New Equipment
(Example from the BNSF San Bernardino Railyard)



*equivalent to power plant PM emissions.

vi. BNSF San Bernardino – Specific Cost Estimates

Between 2015 and 2020, staff estimates that diesel PM emissions from cargo handling equipment at the BNSF San Bernardino Railyard will be reduced to about 0.4 tons per year with the existing regulation.

Electrified RMG Cranes. From 2005 to 2010, the BNSF San Bernardino Railyard operated 13 RTG cranes, plus 6 picks. To replace 13 Tier 4 RTGs in 2015 with electric RMGs (which would also displace nearly all of the 57 Tier 4 yard trucks) would require the installation of an estimated 26 electrified RMGs.

Staff estimates that each electric RMG would cost about $5 million, or a total of about $130 million for 26 electric RMGs. Staff estimates that the necessary electric infrastructure to support electric RMGs would cost an additional $5 million per electric RMG, or a total of about $130 million.

However, the physical configuration of the BNSF San Bernardino Railyard includes a bridge crossing over the railyard with container operations on both sides of the Fourth Street Bridge. Currently, mobile cargo equipment can pass under the bridge and service operations on both sides. An electric RMG is too tall to be installed such that it could service both sides. An electric RMG approach would require either doubling the number of RMGs to cover both sides of the property (at double the above cost) or a significant cost to remove or relocate the bridge.

Total electric RMG capital costs for the BNSF San Bernardino Railyard would be in the range of $260 million-$520 million.

Electric Yard Trucks. In 2005-2010, the BNSF San Bernardino Railyard operated about 57 diesel yard trucks. To replace 57 Tier 4 diesel-fueled yard trucks with electric yard trucks at a cost of about $210,000 per unit, the total capital cost would be $12 million.

vii. BNSF Hobart – Specific Cost Estimates

Between 2015 and 2020, staff estimates that diesel PM emissions from cargo handling equipment at the BNSF Hobart Railyard will be reduced to about 0.8 tons per year with the existing regulation.

Electrified RMG Cranes. From 2005 to 2010, the BNSF Hobart Railyard operated 27 RTG cranes, plus 11 picks. To replace 27 Tier 4 RTGs in 2015 with electric RMGs (which would also displace nearly all of the 114 Tier 4 yard trucks) would require the installation of an estimated 54 electrified RMGs.

Staff estimates that each electric RMG would cost about $5 million, or a total of about $270 million for 54 electric RMGs. Staff estimates that the necessary electric

infrastructure to support electric RMGs would cost an additional $5 million per electric RMG, or a total of about $270 million.

Total electric RMG capital costs for the BNSF Hobart Railyard would be about $540 million.

Electric Yard Trucks. To replace 114 Tier 4 diesel-fueled yard trucks with electric yard trucks at a cost of about $210,000 per unit, the total capital cost would be $24 million.

viii. UP Commerce-Specific Cost Estimates

Between 2015 and 2020, staff estimates that diesel PM emissions from cargo handling equipment at the UP Commerce Railyard will be reduced to about 0.9 tons per year with the existing regulation.

Electrified RMG Cranes. From 2005 to 2010, the UP Commerce Railyard operated 9 RTG cranes, plus one pick. To replace 9 Tier 4 RTGs in 2015 with electric RMGs (which would also displace nearly all of the 26 Tier 4 yard trucks or hostlers) would require the installation of an estimated 18 electrified RMGs.

Staff estimates that each electric RMG would cost about $5 million, or a total of about $90 million for 18 electric RMGs. Staff estimates that the necessary electric infrastructure to support electric RMGs would cost an additional $5 million per electric RMG, or a total cost of $90 million.

Total electric RMG capital costs for the UP Commerce Railyard would be about $180 million.

Electric Yard Trucks. The capital costs to replace 26 diesel yard trucks, with electric yard trucks at about $210,000 per unit, would be a total cost of about $5.5 million.

ix. UP ICTF/Dolores-Specific Cost Estimates

Between 2015 and 2020, staff estimates the diesel PM emissions from cargo handling equipment at the UP ICTF/Dolores Railyards will be reduced to about 0.5 tons per year with the existing regulation.

Electrified RMG Cranes. From 2005 to 2010, the UP ICTF/Dolores Railyards operated 10 RTG cranes, plus three picks. To replace 10 Tier 4 RTGs in 2015 with electric RMGs (which would also displace nearly all of the 73 Tier 4 yard trucks) would require the installation of an estimated 20 electric RMGs. This scenario is based on the current lift capacity of about 750,000 vs. the UP Modernization Plan with 1.5 million lift capacity.

Staff estimates that each electric RMG would cost about $5 million, or a total of about $100 million for 20 electric RMGs. Staff estimates that the necessary electric

infrastructure to support electric RMGs would cost an additional $5 million per electric RMG, or a total cost of $100 million.

Total electric RMG capital costs for the UP ICTF/Dolores Railyards would be about $200 million at current levels of operations without the expansion proposed under the Modernization Plan.

Electric Yard Trucks. The total capital costs to replace 73 diesel yard trucks with electric yard trucks at about $210,000 per unit would equal about $15 million.

c. *Potential Impacts*

i. Impact on Aesthetics

The four high-priority railyards are in continuous operation under well-lighted conditions, 24 hours a day, seven days a week. Under existing conditions, there is already substantial nighttime light and glare from fixed lighting sources.

A regulation for electrification of railyard cargo handling equipment is not likely to result in more brightly lit cargo handling equipment. Changes resulting from a cargo handling equipment electrification regulation are not likely to cause changes in substantial light or glare that would adversely affect day or nighttime views in the area of any of the railyards.

ii. Impact on Noise

The four high-priority railyards covered by the Commitments are large, existing industrial-type operations that already operate 24 hours a day, seven days a week, with on-site and entering/exiting diesel equipment. The physical scale, frequency of activity, noise, and vibration from these operations are part of the existing conditions.

A regulation for cargo handling equipment electrification would result in deployment of new, electrified equipment. Electrified equipment is significantly quieter than the diesel-fueled equipment currently in use at the four high-priority railyards. Therefore, the noise reduction resulting from Alternative C would be a positive impact.

iii. Impact on Transportation and Traffic

On-road container trucks enter and exit the four high-priority railyards, either through a gate complex in one area of the railyard or through entrance and exit gates in separate areas of the railyard. At each railyard, the container trucks take a freeway route on exiting. A regulation for electrification of cargo handling equipment would result in deployment of RMG cranes, which are taller than the RTGs presently in use. At BNSF San Bernardino Railyard, this would necessitate removal or relocation of the Fourth Street Bridge, potentially resulting in temporary or permanent restrictions on

traffic flow in the vicinity of the BNSF San Bernardino Railyard. A cargo handling equipment electrification regulation would therefore have a significant negative impact on transportation and traffic at the BNSF San Bernardino Railyard. At the other three high-priority railyards, a cargo handling equipment electrification regulation would have no impact on transportation or traffic, as the RMG operations would be limited within the railyards.

d. Conclusion

If ARB staff proposed and the Board adopted a regulatory amendment to implement this alternative consistent with State and federal law, the maximum possible estimate of diesel PM emission reductions achievable at the four high-priority railyards would be less than 2.6 tons per year at a cost of well over $1.1 billion. However, some of those emissions would remain but be transferred to the communities where the electric power is generated for use at the railyards. Compared to the proposed project, this alternative would be substantially less effective at achieving the project objective at the four high-priority railyards, with a maximum of 2.6 tons per year of diesel PM reductions in 2020 versus 12.5 tons per year of diesel PM reductions achievable with the Revised 2010 Commitments.

Installation of electric equipment would result in a reduction in noise at all four railyards. This alternative may also result in potential transportation and traffic impacts at the BNSF San Bernardino Railyard if the existing Fourth Street Bridge must be moved to accommodate electric RMG cranes. Because of the reconfiguration that would be needed at the railyards to enable the electric RMG installation and operation, there could be potential short-term construction-related impacts on noise, traffic, and air quality, but the nature and scope of those impacts are unknown at this time.

3. Alternative D: ARB Regulation Requiring Risk Reduction Audits, Plans, and Measures

a. Description of Project Alternative

Under this alternative, the Board could consider adopting a regulation to require railyards to perform risk reduction audits and plans, and implement measures to reduce railyard risks, similar to the existing requirements under the Health and Safety Code "Hot Spots" program that applies to stationary sources and is overseen and enforced by the local air quality management and air pollution control districts.[141] The "Hot Spots" model provides a potential model for an ARB regulation to reduce the health risk from the major railyards in California.

[141] Health and Safety Code §44300 et seq.

b. Evaluation of Feasibility

There are two parts to this evaluation. First, ARB staff provides a summary of the "Hot Spots" program. Then, we explore ARB's authority to adopt a regulation consistent with State and federal law to establish similar requirements for railyard facilities dominated by mobile source emissions.

i. "Hot Spots" Statutes

The Air Toxics "Hot Spots" Information and Assessment Act (AB 2588, 1987, Connelly) was enacted in September 1987. Under this legislation, "stationary sources" are required to report the types and quantities of certain substances their facilities routinely release into the air. The goals of the Air Toxics "Hot Spots" Act are to collect emission data, to identify facilities having localized impacts, to ascertain health risks, and to notify nearby residents of significant risks. In September 1992, the "Hot Spots" Act was amended by Senate Bill (SB) 1731 (Calderon) to address the reduction of significant risks. Statute now also requires that owners of significant-risk facilities reduce those risks below the level of significance.

The current statutory requirements are in Health and Safety Code §44391, which requires facilities presenting a significant risk (as determined by the air district) to conduct a risk reduction audit and develop a plan to implement measures to reduce that risk within five years of the date the plan is submitted to the district. The period to implement the plan may be shortened by the district if it finds that it is technically feasible and economically practicable to implement the plan more quickly or finds that the emissions from the facility pose an unreasonable health risk. However, a district may lengthen the plan implementation period by up to an additional five years based on factors such as economic burden to the facility operator or technical feasibility of the plan.

ii. Air District Risk Levels

Each district has selected a risk threshold value for the projected maximum individual cancer risk (expressed as chances in a million) at which facilities must conduct a risk reduction audit and plan.[142] The current risk threshold value for the South Coast Air Quality Management District and the Sacramento Metropolitan Air Quality Management District is 25 in a million. Risk threshold values for the San Joaquin Valley, Bay Area, and Mojave Desert are 100 in a million. The implementation plan component of the "Hot Spots" program, through Health and Safety Code §44391, has proved to be an effective mechanism for reducing toxic emissions at stationary facilities.

[142] http://www.arb.ca.gov/ab2588/district_levels.htm. Web archive, May 6, 2011.

iii. ARB Authority to Adopt a Similar Program for Railyards

ARB staff believes that a similar program could be developed under the broad authority granted ARB under Health and Safety Code §39650 et seq. to develop a statewide program to control toxic air contaminants, subject to federal preemption. As with other airborne toxic control measures, ARB would have to consider, among other things, the cost-effectiveness of the adopted program and the types of emission/risk reduction measures that the railroads would need to implement.

For the reasons set forth in the earlier analysis of Alternative B, federal preemption would likely significantly restrict ARB's authority to regulate the largest railyard emission source, i.e., locomotives. The CAA preemption alone would preempt a State requirement for risk reduction measures that apply to federal complying locomotives, which on average would represent about 70 percent of remaining railyard diesel PM emissions at the four high-priority railyards by 2020.

Under existing ARB and U.S. EPA regulations and agreements, railyard emissions from cargo handling equipment, drayage trucks, and transport refrigeration units (TRUs) will reduce by 90 percent or more between 2015 and 2020. As explained under Alternative C above regarding possible amendments to the cargo handling equipment regulation, further regulation of these sources (e.g., electrification of TRUs) is currently not cost-effective, arguably precluding ARB adoption of an emission/risk reduction program that relies upon emission reductions from these sources under authority granted in the Health and Safety Code. Moreover, while these regulations apply across several industrial sectors, it could be argued that further regulation of these sources at railyards alone is discriminatory and – when considered with the cost-effectiveness of the regulations – unduly burdensome, making harmonization with ICCTA problematic.[143]

iv. Emission Reduction Benefits

It is not possible to accurately quantify the emission reductions that would result from implementation of this alternative without defining a risk threshold and doing air quality modeling to back-calculate the reductions that would be needed from non-locomotive sources to meet it. However, staff has provided an upper bound number based on the universe of diesel PM sources at the four priority railyards – excluding preempted locomotives. Since there are no non-preempted locomotives routinely operating at the four priority railyards, there are no emissions from these sources to include. The sum of diesel PM emissions for all non-locomotive sources at the four yards in 2020 under the existing program is 7.4 tons per year. If the railroads electrified every non-locomotive mobile source, most of these emissions could be eliminated from the yard itself. However, an ARB regulation establishing a risk threshold for railyards or applying the existing district thresholds for stationary sources would need to identify a feasible path to meet the threshold in a cost-effective way, consistent with State and federal law.

[143] *AAR v. SCAQMD, supra,* 622 F.3d at 1098.

c. Potential Impacts

i. Impact on Aesthetics

The four high-priority railyards are in continuous operation under well-lighted conditions, 24 hours a day, seven days a week. Under existing conditions, there is already substantial nighttime light and glare from fixed lighting sources. A regulation to reduce diesel PM emissions at railyards is not likely to result in more brightly lit railyard equipment. Changes resulting from such a regulation are not likely to cause changes in substantial light or glare that would adversely affect day or nighttime views in the area of any of the railyards.

ii. Impact on Noise

The four high-priority railyards covered by the Revised 2010 Commitments are large, existing industrial-type operations that already operate 24 hours a day, seven days a week, with on-site and entering/exiting diesel equipment. The physical scale, frequency of activity, noise, and vibration from these operations are part of the existing conditions. A regulation to reduce railyard diesel PM health risk would likely result in deployment of new, electrified railyard equipment. Electrified railyard equipment is significantly quieter than the diesel-fueled equipment currently in use at the four high-priority railyards. Therefore, the noise reduction resulting from Alternative D would be a positive impact.

iii. Impact on Transportation and Traffic

Trucks enter and exit the four high-priority railyards, either through a gate complex in one area of the railyard or through entrance and exit gates in separate areas of the railyard. At each railyard, the container trucks take a freeway route on exiting. A regulation to reduce railyard diesel PM health risk would likely result in deployment of rail mounted gantry (RMG) cranes, which are taller than the RTGs presently in use. As discussed under Alternative C, this would have a significant negative impact on transportation and traffic at the BNSF San Bernardino Railyard.

One of the approaches that the railroads could employ to meet a risk threshold without reductions from preempted locomotives is an electric truck fleet to serve the railyard. Based on current technology and battery range, this would likely require electric truck charging stations at or near the railyard and new operations to support truck queuing and time out of service to access the charging stations. These operations would likely increase the total volume of truck traffic needed to meet the railyard's cargo demands and could impact traffic at each of the high-priority railyards.

d. Conclusion

This alternative would be less effective in meeting the project objective than the Revised 2010 Commitments because any requirements to reduce the health risk from the high-priority railyards would need to exclude the diesel PM emissions from preempted locomotives, the largest remaining source. The total remaining diesel PM emissions in 2020 subject to control under this alternative would be 7.4 tons per year for all four railyards combined. If all of these on-site emissions were eliminated through electrification, it would still be substantially less effective than the 12.5 tons per year of diesel PM reductions achievable under the proposed project.

The conclusions for Alternative C would also apply to Alternative D because both would be likely to result in reconfiguration at the railyards to enable electric RMG installation and operation. Installation of electric equipment would result in a reduction in noise at all four railyards. This alternative may also result in potential transportation and traffic impacts at the BNSF San Bernardino Railyard if the existing Fourth Street Bridge must be moved to accommodate electric RMG cranes. Because of the reconfiguration that would be needed at the railyards to enable the electric RMG installation and operation, there could be potential short-term construction-related impacts, but the nature and scope of those impacts are unknown at this time.

ATTACHMENT 1

Environmental Checklist

ARB used the environmental checklist criteria included in Appendix G of the CEQA Guidelines as a basis for assessing the potential significant adverse environmental impacts. ARB's findings are supported by documents incorporated by reference into this environmental analysis.

The environmental impacts checked below indicate those that may be affected by the Revised 2010 Commitments. Further discussion follows each major category of potential impact.

For this project, the following designations are used:

Potentially Significant Impact: An impact that could be significant and discussed in the Impact Analysis chapter of the FED.
Less Than Significant With Mitigation Incorporated: An impact that requires mitigation to reduce the impact to a less-than-significant level.
Less Than Significant: Any impact that would not be considered significant under CEQA relative to existing standards.
No Impact: Any impact that does not apply to the project.

Evaluation of Environmental Impacts

I. AESTHETICS. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Have a substantial adverse effect on a scenic vista?	☐	☐	☐	☒
b) Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a State scenic highway?	☐	☐	☐	☒
c) Substantially degrade the existing visual character or quality of the site and its surroundings?	☐	☐	☐	☒
d) Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☒	☐	☐	☐

Discussion: The four high-priority railyards are large, existing industrial-type operations that run 24 hours a day, seven days a week, with diesel equipment on-site and entering/exiting the railyards. The physical scale of these railyards and their equipment typically precludes community residents from experiencing scenic views adjacent to the railyards; therefore the project will have no impact on scenic vistas. Operational changes on-site of the railyards will not damage scenic resources including but not limited to trees, rock outcroppings, and historic buildings within a State scenic highway.

The potential for the creation of new sources of substantial light or glare is discussed in the FED Impact Analysis chapter.

II. AGRICULTURE AND FOREST RESOURCES. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use?	☐	☐	☐	☒
b) Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☐	☒
c) Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined by Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code §51104(g))?	☐	☐	☐	☒
d) Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☐	☒
e) Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland, to non-agricultural use or conversion of forest land to non-forest use?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing facilities that are not located on farmland or forest land. They are located in urban areas and physically constrained from increasing the footprint of their operations, except for the UP ICTF/Dolores Railyards.[144] Implementation of the Revised 2010 Commitments would not adversely impact the existing forest and agricultural resources.

[144] *Application for Development Project Approval, Intermodal Container Transfer Facility (ICTF) Modernization Project* (December 26, 2007, p.3). In Appendix H of this report there is a Phase I Environmental Site Assessment for an adjacent property outside of the ICTF footprint which UP anticipates may be developed for the modernization project (shown in Figure 2 of the Environmental Site Assessment).

III. AIR QUALITY. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☐	☐	☒
b) Violate any air quality standard or contribute substantially to an existing or projected air quality violation?	☐	☐	☐	☒
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or State ambient air quality standard (including releasing emissions which exceed quantitative thresholds for ozone precursors)?	☐	☐	☐	☒
d) Expose sensitive receptors to substantial pollutant concentrations?	☐	☐	☐	☒
e) Create objectionable odors affecting a substantial number of people?	☐	☐	☐	☒

Discussion: Implementation of the Revised 2010 Commitments would substantially decrease, not increase, air pollution and the associated health risk. The Commitments would reduce the exposure of residents of surrounding communities to toxic air pollutant concentrations and reduce the criteria pollutants that contribute to violations of air quality standards by cutting the diesel PM, NOx, and VOC emissions from railyard operations. Staff expects the impact on SOx emissions to be either neutral because the emission reduction technologies do not provide additional SOx control or beneficial because use of more fuel-efficient locomotives to meet the Commitments would result in lower emissions of SOx (and other pollutants). Applicable air quality plans prepared by local, regional, and State agencies specifically rely on new emission reductions from locomotives to meet air quality standards and toxic reduction targets. A more detailed discussion of the beneficial impacts on air quality is provided in the FED Impact Analysis chapter.

If the railroads choose to implement operational changes that involve construction, there could be potential short-term construction-related impacts to air quality due to the temporary generation of criteria and toxic air pollutants (e.g., use of diesel-fueled construction equipment and creation of fugitive dust), but the nature and scope of such impacts are unknown at this time.

IV. BIOLOGICAL RESOURCES. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☒
b) Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, and regulations or by the California Department of Fish and Game or US Fish and Wildlife Service?	☐	☐	☐	☒
c) Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☐	☒
d) Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☐	☒

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
e) Conflict with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☐	☒
f) Conflict with the provisions of an adopted Habitat Conservation Plan, Natural Community Conservation Plan, or other approved local, regional, or State habitat conservation plan?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing facilities and are not located on riparian land, in a sensitive natural community, or in federally protected wetlands. They are in urban areas and physically constrained from increasing the footprint of their operations, except for the UP ICTF/Dolores Railyards.[145] The project will have no impact or substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service. Implementation of the Commitments will not interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites because the Commitments will not result in a change in use of the sites. The project will not conflict with the provisions of any approved local, regional, State, or federal habitat conservation plans as none are applicable to the project sites.

[145] *Application for Development Project Approval, Intermodal Container Transfer Facility (ICTF) Modernization Project* (December 26, 2007), p. 3.

V. CULTURAL RESOURCES. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Cause a substantial adverse change in the significance of a historical resource as defined in CEQA Guideline §15064.5?	☐	☐	☐	☒
b) Cause a substantial adverse change in the significance of an archaeological resource pursuant to CEQA Guideline §15064.5?	☐	☐	☐	☒
c) Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?	☐	☐	☐	☒
d) Disturb any human remains, including those interred outside of formal cemeteries?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing large industrial-type operations that have been operating for decades:

BNSF San Bernardino Railyard: California Southern Railroad opened the San Bernardino railyard, with the opening of the Cajon Pass, in 1885.[146] Atchison, Topeka & Santa Fe (ATSF) began intermodal operations in 1986.[147] All of the identified cultural sites in San Bernardino's General Plan EIR are located north of East 40th Avenue off of Rim of the World Highway, near Arrowhead Springs Road – about five miles from the BNSF San Bernardino Railyard.

BNSF Hobart Railyard: The Los Angeles and Salt Lake Railroad rail company, incorporated in 1901, completed and operated a railway line between Los Angeles and Salt Lake City, Utah, via Las Vegas, Nevada.[148]

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[146] http://en.wikipedia.org/wiki/California_Southern_Railroad. Web archive, March 16, 2011.
[147] Economics & Politics, Inc., *Hemet: Demographic, Economic & Quality of Life Data*, September 2005, p. 50.
[148] http://en.wikipedia.org/wiki/San_Pedro,_Los_Angeles_and_Salt_Lake_Railroad. Web archive, March 16, 2011.

Intermodal operations began in 1952 on two dedicated tracks.[149] According to the General Plan EIRs, the cities of Commerce and Vernon do not contain any known archaeological or paleontological resources.

UP Commerce Railyard: The Los Angeles and Salt Lake Railroad built this yard in 1924. UP shut the classification yard hump operations in 1990 to shift operational emphasis to intermodal activities.[150] According to the General Plan EIRs, the cities of Commerce and Vernon do not contain any known archaeological or paleontological resources.

UP ICTF/Dolores Railyards: ICTF opened in 1986.[151] Dolores was built by Pacific Electric in 1943 to support growing harbor activity during World War II.[152] There are no paleontological resources within the City of Carson, but there are two identified cultural sites. The first cultural site identified in the General Plan EIR is located at 18127 Alameda Street, about five miles north of the UP ICTF Railyard. The second site is located at the southeast corner of East 230th Street and Utility Way, about a mile west of the UP ICTF Railyard. All of the cultural sites identified in the Historic Preservation Document (part of the forthcoming Long Beach 2030 General Plan) are east of the Long Beach Freeway.

ARB anticipates that the railroads will purchase and operate cleaner locomotives and yard equipment to meet the emission reduction levels in the Revised 2010 Commitments. The railroads may undertake physical changes in the facility itself as part of operational changes to reduce health risks. Such changes may involve digging and construction, for example, when trenching for electrical infrastructure for electrification of cranes. Such land disturbances, however, are not expected to affect any historical resources, archaeological resources, paleontological resources or unique geological features, nor disturb any human remains, because the land disturbances would primarily involve the removal of existing pavement and only incidental removal of soil. There is not a reasonable likelihood that implementation of the Revised 2010 Commitments would have a significant adverse effect on Cultural Resources.

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[149] BNSF Railway, *Los Angeles (Hobart) and Commerce BNSF Intermodal Facilities.* Informational brochure provided by BNSF to ARB, May 2010.
[150] Solomon, Brian, *Union Pacific Railroad*, 2000, pp. 69-70.
[151] http://www.uprr.com/customers/intermodal/featured/ictf/index.shtml. Web archive, March 16, 2011.
[152] http://www.erha.org/pesspd.htm. Web archive, March 16, 2011.

VI. GEOLOGY AND SOILS. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☐	☒
i) Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault? Refer to Division of Mines and Geology Special Publication 42.	☐	☐	☐	☒
ii) Strong seismic ground shaking?	☐	☐	☐	☒
iii) Seismic-related ground failure, including liquefaction?	☐	☐	☐	☒
iv) Landslides?	☐	☐	☐	☒
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☐	☒
c) Be located on a geologic unit or soil that is unstable, or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☐	☒
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☐	☒

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
e) Have soils incapable of adequately supporting the use of septic tanks or alternative waste water disposal systems where sewers are not available for the disposal of waste water?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing large industrial-type operations that have been operating at their current urban sites for decades. Because these particular railyards are intermodal railyards, most of the land between the tracks at each site is paved or built over. ARB anticipates that any technological changes or operational changes that the railroads would pursue to meet the emission reduction levels would not make significant physical changes in the facility. Although some operational changes may involve some digging or trenching, this would not result in substantial soil erosion or the loss of topsoil, because it would primarily involve the removal of existing pavement and only incidental removal of soil. Furthermore, the project will not alter or add uses to the sites, will not involve any land alteration that could increase exposure of people or structures to seismic and landslide risks, and will not increase risk to people or property from any type of soil instability. There is not a reasonable likelihood that implementation of the Revised 2010 Commitments will have a significant adverse effect on geology and soils.

VII. GREENHOUSE GAS EMISSIONS. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?	☐	☐	☐	☒
b) Conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases?	☐	☐	☐	☒

Discussion: The 2010 Revised Commitments would reduce the environmental impact of Southern California operations regardless of growth. A shift in freight from truck transport to rail transport has a net benefit for climate change. Moving cargo by rail emits approximately 75 percent less carbon dioxide (CO2) emissions than moving that same cargo by truck.[153]

Emissions of CO2 and other greenhouse gases track closely with diesel fuel burned. Implementation of the Revised 2010 Commitments will continue the turnover of the switch locomotive fleet that primarily operates in the railyards to multi-engine generator set technology that reduces fuel consumption by 20 to 40 percent as compared to older switch locomotives.[154] While the level of greenhouse gas emissions from new advanced technology line haul locomotives is uncertain since the technology does not yet exist, ARB staff expects that these new units will have equivalent or better fuel economy than current models. With fuel comprising the second largest cost for railroad operations, the railroads are exerting pressure on the technology developers to ensure that next generation locomotives have no fuel consumption penalty, despite the addition of multiple air pollution control devices. Black carbon is a constituent of diesel PM and a fast-acting climate change contributor. The primary objective of the Revised 2010 Commitments is to reduce diesel PM, which will also reduce black carbon.

[153] *The Economic Impact of America's Freight Railroads*, American Association of Railroads, May 2010.
[154] Air Resources Board, *Technical Options to Achieve Additional Emissions and Risk Reductions from California Locomotives and Railyards*, August 2009, p. 45.

VIII. HAZARDS AND HAZARDOUS MATERIALS. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials?	☐	☐	☐	☒
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?	☐	☐	☐	☒
c) Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☐	☐	☐	☒
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would it create a significant hazard to the public or the environment?	☐	☐	☐	☒
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☒
f) For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☒

	Potentially Significant	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
g) Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☒
h) Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☐	☐	☒

Discussion: The railroads already transport and handle railcars containing hazardous materials, consistent with federal, State and local requirements. None of the four high-priority railyards is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5.

Since the railyards are in established urban areas, it is not foreseeable that any action attributable to the Revised 2010 Commitments would affect the likelihood of wildland fires; therefore the likelihood of wildland fires is not analyzed further in the FED. Railyard facilities are highly specialized facilities consisting of one or more areas including engine maintenance buildings, fueling areas, track and switching areas, and track maintenance/material storage yards. The raw materials associated with this industry are primarily used in fueling and maintenance operations. The maintenance/material storage yard areas use a wide variety of solvents, paints, treated railroad ties and wastes.[155]

Interstate line haul locomotive manufacturers, currently General Electric (GE) and Electro-Motive Diesel (EMD), must meet the U.S. EPA Tier 4 interstate line haul locomotive oxides of nitrogen (NOx) emission standard of 1.3 g/bhp-hr by 2015. U.S. EPA and locomotive manufacturers agree the Tier 4 NOx standard will be met with either exhaust gas recirculation (EGR) or selective catalytic reduction (SCR) aftertreatment systems. Locomotive EGR and SCR will likely be part of an aftertreatment system that will also include a diesel oxidation catalyst (DOC) and diesel particulate filter (DPF). DOCs and DPFs are devices designed primarily to reduce locomotive PM emissions to meet the U.S. EPA Tier 4 PM level of 0.03 g/bhp-hr.

[155] U.S. EPA Industry Profile, Rail Yards: http://www.epa.gov/reg3hwmd/bf-lr/regional/industry/railyard.htm. Web archive, March 16, 2011.

At this time, neither GE nor EMD has formally announced which NOx approach will be employed with Tier 4 locomotives. However, recent discussions indicate that both GE and EMD are focusing efforts on a non-SCR based approach to respond to railroads' concerns about increased life-cycle costs and the need for a national supply infrastructure to provide the urea required for SCR.

EGR works by recirculating a portion of an engine's exhaust gas back to the engine cylinders. In a diesel engine, the exhaust gas replaces some of the excess oxygen in the pre-combustion mixture. Because NOx forms primarily when a mixture of nitrogen and oxygen is subjected to high temperature, the lower combustion chamber temperatures caused by EGR reduce the amount of NOx the combustion generates.

The federal government comprehensively regulates the transportation of hazardous materials. Under the railroads' common carrier obligation to transport hazardous materials, the railroads are subject to numerous special procedures contained in Department of Transportation / Pipeline and Hazardous Materials Safety Administration (DOT/PHMSA) and Department of Homeland Security / Transportation Security Administration (DHS/TSA) rules, relating to the handling and storage of hazardous materials.[156] The PHMSA issues hazardous materials regulations for railroads[157] that are enforced by the Federal Railroad Administration (FRA); TSA issues hazardous materials regulations for railroads[158] from a security perspective.

The federal regulations governing the transportation of hazardous materials by rail govern operating practices, tank car requirements, and other aspects of hazardous materials transportation. PHMSA regulations require that:

- Railroads must compile annual data on certain shipments of explosive, toxic by inhalation, and radioactive materials; use the data to analyze safety and security risks along rail routes where those materials are transported; assess alternative routing options; and make routing decisions based on those assessments.
- Rail carriers must have security plans and address the security of shipments from origin to destination.
- When a railroad receives hazardous materials in a train, the railroad must conduct a safety and security inspection of the railcars containing hazardous materials.

In analyzing impact, staff assumed the Revised 2010 Commitments would result in the accelerated introduction of Tier 4 interstate line haul locomotives, which may rely on SCR technology to reduce NOx emissions and require the use of urea, which by itself is not a hazardous substance. But the combustion of urea in SCR technology produces ammonia emissions, which are limited by emission standards.

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[156] BNSF Railway Company, Ex-Parte No. 677 (Sub-No. 1), Common Carrier Obligation of Railroads – Transportation of Hazardous Materials. Presentation by BNSF to Surface Transportation Board, DOE, July 22, 2008.
[157] Title 49, Code of Federal Regulations, Part 174.
[158] Title 49, Code of Federal Regulations, Part 1580.

Ammonia is listed as a hazardous substance both federally and in California. Federal listings include:

- Air Contaminants (Occupational Safety and Health Act)
- Extremely Hazardous Substances (Superfund)
- Hazardous Substances (Superfund)
- Registered Pesticides (Federal Insecticide, Fungicide, and Rodenticide Act)
- Regulated Toxic, Explosive, or Flammable Substances (Clean Air Act)
- Toxic Release Inventory Chemicals

Ammonia is listed in the 2007 (Comprehensive Environmental Response, Compensation, and Liability Act) CERCLA priority list as a hazardous substance.[159] The CERCLA priority list is developed based on toxicity, frequency of occurrence at pre-Superfund sites, and potential for human exposure. In California, ammonia is listed as hazardous substance under California Occupational Safety and Health Regulations.[160]

Railroads currently store and dispense large volumes of diesel fuel and oil, and handle a variety of hazardous materials for use with stationary sources within most railyards. The Revised 2010 Commitments will not lead to changes in how UP and BNSF handle hazardous materials or comply with existing regulations.

One of the key challenges with SCR on an interstate line haul locomotive is being able to design a system that precisely meters urea to approach a one to one conversion ratio between urea to NOx, and to minimize potentially toxic emissions from ammonia slip.[161]

U.S. EPA responded to the potential for SCR technology to convert urea into ammonia in its 2008 locomotive rulemaking. Please see the U.S. EPA response below with respect to unregulated pollutants:[162]

> There is potential for the formation of unregulated pollutants of significant concern to EPA any time engine technologies change, including when new emission control technologies are added. Some examples of these unregulated pollutants include nitrous oxide (N_2O) and ammonia. In addition, failure to dose urea in an SCR system while operating under load may cause elevated nitrogen dioxide (NO_2) emissions.
>
> Similarly, use of a catalyzed diesel particulate filter that produces NO_2 in excess of what is needed for passive regeneration – and operated without a downstream SCR system – may lead to elevated NO_2 emissions. Such increased NO_2 emissions could be a concern for operation in enclosed environments such as locomotive operation in minimally ventilated or unventilated tunnels. Similarly, use of NO_X reduction catalysts with poor selectivity could result in elevated

[159] http://www.atsdr.cdc.gov/cercla/07list.html. Web archive, May 6, 2011.
[160] Title 8, California Code of Regulations, §339(b)(3).
[161] *Technical Options Document*, August 2009, p. 166.
[162] *Federal Register*, Volume 73, Number 88, pp. 25098-25352, May 6, 2008.

N_2O emissions. An aggressive urea dosing strategy within an SCR system (for high levels of NO_X control) without a properly designed/calibrated feedback control system, ammonia slip catalyst, or adequate exhaust/urea mixing could also result in elevated ammonia emissions.

SCR-related ammonia emissions can be minimized through the use of closed-loop feedback and control of urea injection, and all but eliminated through use of an oxidation catalyst downstream of the SCR catalyst. Such catalysts, commonly referred to as slip catalysts, are in use today and have been shown to be highly effective at eliminating ammonia emissions.[163]

We expect locomotive manufacturers to be conscious of these possibilities and to take appropriate action to minimize or prevent the formation of unregulated pollutants when designing emission control systems. Manufacturers must comply with the *Prohibited Controls* section of Title 40 Code of Federal Regulations, §1033.115(c), which states:

> *"You may not design or produce your locomotives with emission control devices, systems, or elements of design that cause or contribute to an unreasonable risk to public health, welfare, or safety while operating. For example, this would apply if the locomotive emits a noxious or toxic substance it would otherwise not emit that contributes to such an unreasonable risk."*

Emission control systems designed to meet the 2007 and 2010 heavy-duty truck and Tier 2 light-duty vehicle emission standards already take these unregulated pollutants into account through compliance with Section 202(a)(4) of the Clean Air Act. Catalyzed diesel particulate filter systems that minimize formation of excess NO_2 while still relying primarily on passive regeneration have entered production for OEM and retrofit applications. Compact urea-SCR systems that have been developed to meet the U.S. 2010 heavy-duty truck standards use closed-loop controls that continuously monitor NOx reduction performance. Such systems have the capability to control stack emissions of ammonia to below 5 parts per million (ppm) during transient operation, even without the use of an ammonia slip catalyst. We understand that such systems may still emit some very small level of uncontrolled pollutants, and we would not generally consider a system that releases de minimis amounts of ammonia or N_2O while employing technology consistent with limiting these emissions, to be in violation of Title 40 Code of Federal Regulations, §1033.115(c) – which is the same way we currently treat passenger cars and heavy-duty trucks with regard to N_2O and hydrogen sulfide (H_2S) emissions.

For each of the railyards, changes in operations resulting from the Revised 2010 Commitments are not likely to cause changes in how any hazardous materials are transported through or used at the railyard. It is possible that changes in operations at the railyards could result in the moving of maintenance facilities which use hazardous materials to another on-site location. However, specific provisions under State and federal law govern the safe handling of these materials. The Revised 2010 Commitments do not cause any changes to the handling of such materials.

[163] Smedler, G., *NOx Emission Control Options*, 2007 HDD Emission Control Symposium – Gothenberg, Sweden, September 11, 2007, pp. 1-31.

IX. HYDROLOGY AND WATER QUALITY. Would the Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Violate any water quality standards or waste discharge requirements?	☐	☐	☐	☒
b) Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g., the production rate of preexisting nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☐	☐	☐	☒
c) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, in a manner which would result in substantial erosion or siltation on- or off-site?	☐	☐	☐	☒
d) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner which would result in flooding on- or off-site?	☐	☐	☐	☒
e) Create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☐	☒

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
f) Otherwise substantially degrade water quality?	☐	☐	☐	☒
g) Place housing within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map?	☐	☐	☐	☒
h) Place within a 100-year flood hazard area structures which would impede or redirect flood flows?	☐	☐	☐	☒
i) Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam?	☐	☐	☐	☒
j) Inundation by seiche, tsunami, or mudflow?	☐	☐	☐	☒

Discussion: The four high-priority railyards are large existing facilities with fixed tracks and heavy diesel equipment operating on the tracks, on paved ground, and on unpaved ground. It is not foreseeable that the railroads would alter the land use at these sites in response to the Revised 2010 Commitments; thus it is not reasonably foreseeable that implementation of the Commitments would have a significant adverse effect on Hydrology and Water Quality.

X. LAND USE AND PLANNING. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Physically divide an established community?	☐	☐	☐	☒
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program, or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☐	☒
c) Conflict with any applicable habitat conservation plan or natural community conservation plan?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing large industrial-type operations that have been operating at their current urban sites for decades. Most of the land at each site is paved, built over, or covered with railroad tracks. ARB anticipates the railroads would purchase and operate cleaner locomotives and yard equipment to meet the emission reduction levels in the Revised 2010 Commitments, and that any operational changes implemented would not affect land use or change existing land uses since the facilities are part of the existing conditions. It is not reasonably foreseeable that implementation of the Revised 2010 Commitments would have a significant adverse effect on Land Use and Planning.

XI. MINERAL RESOURCES. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the State?	☐	☐	☐	☒
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing large industrial-type operations that have been operating at their current urban sites for decades. Most of the land at each site is paved, built over, or covered with railroad tracks. There is not a reasonable likelihood that implementation of the Revised 2010 Commitments would have a significant adverse effect on Mineral Resources.

XII. NOISE. Would the Revised 2010 Commitments cause the:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Exposure of persons to or generation of noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☒	☐	☐	☐
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	☒	☐	☐	☐
c) A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☐	☒
d) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	☒	☐	☐	☐
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☐	☒
f) For a project within the vicinity of a private airstrip, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☐	☒

Potential noise impacts are discussed in the Impact Analysis chapter of the FED.

XIII. POPULATION AND HOUSING. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Induce substantial population growth in an area, either directly (for example, by proposing new homes and businesses) or indirectly (for example, through extension of roads or other infrastructure)?	☐	☐	☐	☒
b) Displace substantial numbers of existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☒
c) Displace substantial numbers of people, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing large industrial-type operations that have been operating at their current urban sites for decades. There is no residential housing on these properties. There is not a reasonable likelihood that implementation of the Revised 2010 Commitments would have a significant adverse effect on Population and Housing.

XIV. PUBLIC SERVICES

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Would the proposed project result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the public services:	☐	☐	☐	☒
b) Fire protection?	☐	☐	☐	☒
c) Police protection?	☐	☐	☐	☒
d) Schools?	☐	☐	☐	☒
e) Parks?	☐	☐	☐	☒
f) Other public facilities?	☐	☐	☐	☒

Discussion: The implementation of the project will occur at four existing industrial railyards. Any changes that occur at the railyards will not require any changes to governmental facilities. There is no reasonable likelihood that implementation of the Revised 2010 Commitments would have a significant adverse effect on Public Services.

XV. RECREATION

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☐	☒
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities which might have an adverse physical effect on the environment?	☐	☐	☐	☒

Discussion: The implementation of the project will occur at four industrial railyards and there is not a reasonable likelihood that it will result in impacts on parks or other facilities.

XVI. TRANSPORTATION AND TRAFFIC. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit?	☐	☐	☐	☒
b) Conflict with an applicable congestion management program, including, but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways?	☒	☐	☐	☐
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	☐	☐	☐	☒
d) Substantially increase hazards due to a design feature (e.g., sharp curves or dangerous intersections) or incompatible uses (e.g., farm equipment)?	☐	☐	☐	☒
e) Result in inadequate emergency access?	☐	☐	☐	☒

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
f) Conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities?	☐	☐	☐	☒

Discussion: The four high-priority railyards are existing facilities and the proposed project will not cause any new uses that would cause additional traffic that could conflict with applicable plans or programs. The existing conditions include rail crossings at grade with streets. The Revised 2010 Commitments are not expected to change how trains enter or exit one of the railyards and therefore would not change any existing delays in emergency access by motor vehicles needing to cross the railroad tracks.

Further analysis of the potential for changes to traffic in the vicinity of the railyards is discussed in the Impact Analysis chapter of the FED.

XVII. UTILITIES AND SERVICE SYSTEMS. Would the Revised 2010 Commitments:

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board?	☐	☐	☐	☒
b) Require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☐	☒
c) Require or result in the construction of new storm water drainage facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☐	☒
d) Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☐	☐	☐	☒
e) Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing project?	☐	☐	☐	☒
f) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☐	☐	☐	☒
g) Comply with federal, state, and local statutes and regulations related to solid waste?	☐	☐	☐	☒

Discussion: The four high-priority railyards are large, industrial-type facilities supported by existing water, wastewater, and waste disposal services. Most of the land at each site is paved, built over, or covered with railroad tracks. ARB anticipates that any technological or operational changes resulting from the Revised 2010 Commitments will not result in changes that would affect these services since the primary purpose of the railyard is to move freight.

If any railroad concludes that site operational changes (such as moving a truck entrance gate or installing a large electric rail-mounted gantry crane) offer a cost-effective option to reduce emissions, the railroad may pursue such changes. It is highly speculative that any such changes might require a corresponding change in the storm water drainage facilities. There is not a reasonable likelihood that implementation of the Revised 2010 Commitments would have a significant adverse effect on Utilities and Service Systems.

XVIII. MANDATORY FINDINGS OF SIGNIFICANCE

	Potentially Significant Impact	Less Than Significant with Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☒
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)?	☒	☐	☐	☐
c) Does the project have environmental effects which will cause substantial adverse effects on human beings, either directly or indirectly?	☐	☐	☐	☒

Discussion: The proposed project will occur at four existing industrial paved-over railyards. The project does not have the potential to substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory. Potential cumulative impacts are discussed under the Cumulative and Growth-Inducing Impacts chapter of the FED. The proposed project would have clear and substantial air quality benefits to nearby residents and the surrounding region.

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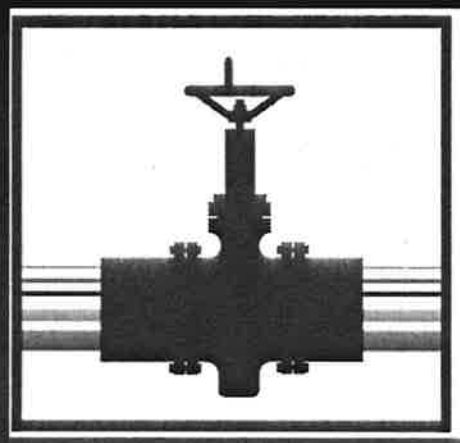
Revised 2010 Commitments for Four High-Priority Railyards
CEQA Functional Equivalent Document



PLAINS ALL AMERICAN PIPELINE, L.P.

Crude Oil Trends & Recent Developments

Greg L. Armstrong, Chairman & CEO

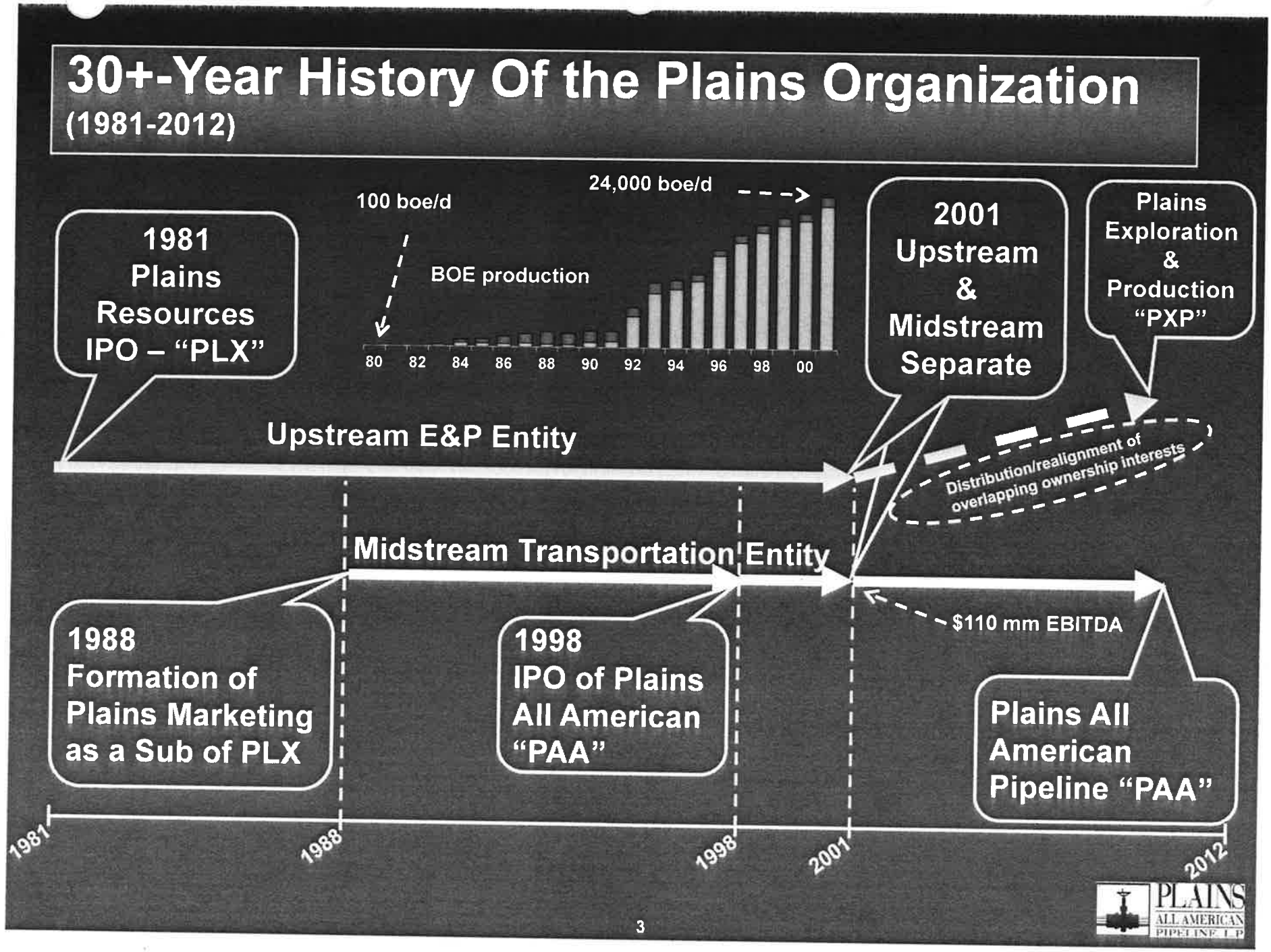
IPAA & TIPRO
Leaders in Industry
Houston, TX
January 11, 2012

Today's Presentation

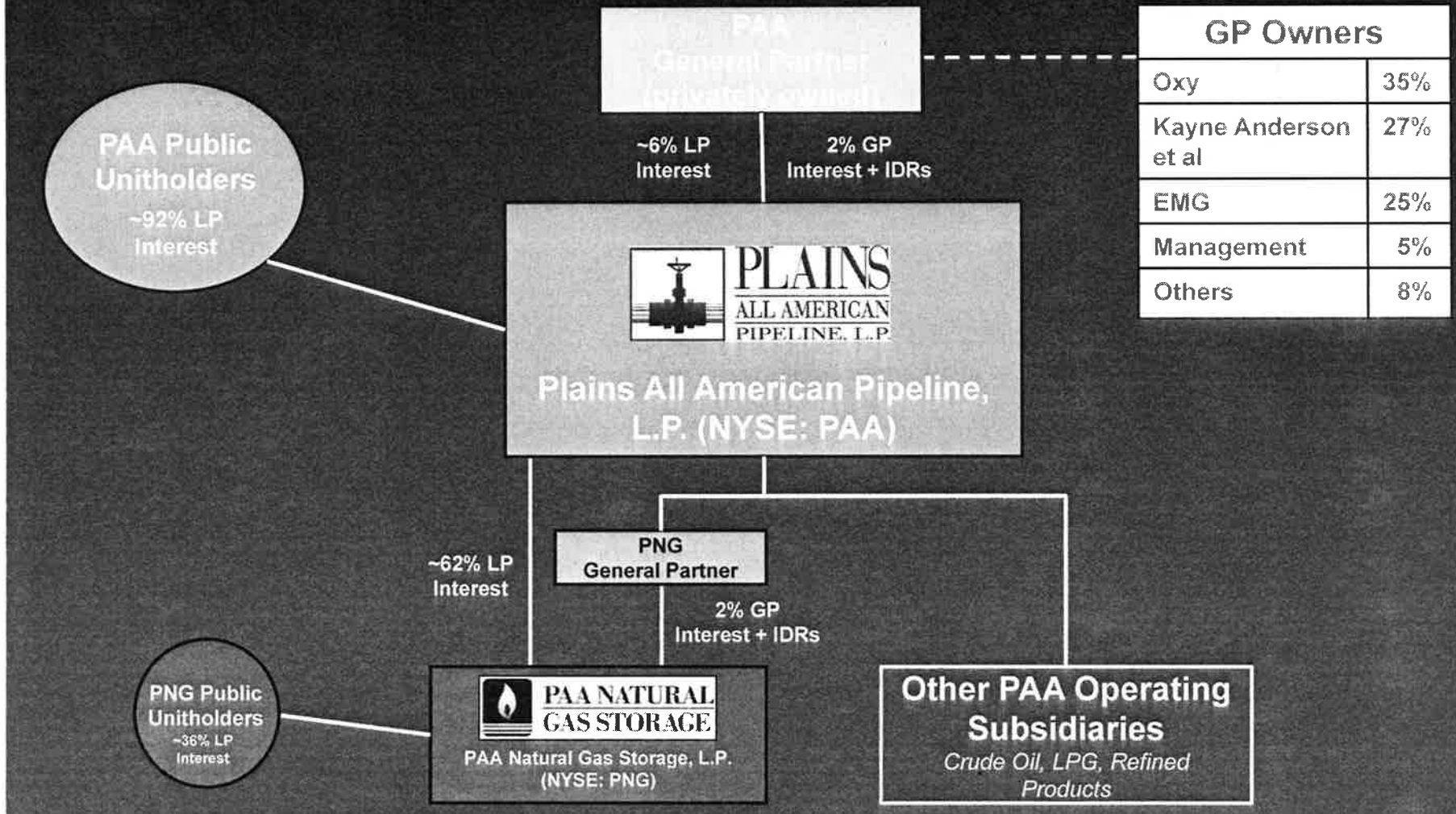
- Introduction to Plains All American Pipeline, L.P.
- Industry topics:
  - ✓ Macro U.S. petroleum trends
  - ✓ Increased crude oil drilling and production & related issues
  - ✓ Impact of increased U.S. oil production compared to increased natural gas production
  - ✓ Potential crude oil quality issues
  - ✓ WTI Brent differential
- A few thoughts on crude oil and natural gas in 2012

PLAINS ALL AMERICAN PIPELINE, L.P.

30+-Year History Of the Plains Organization
(1981-2012)



PAA Ownership Structure



GP Owners	
Oxy	35%
Kayne Anderson et al	27%
EMG	25%
Management	5%
Others	8%

Adjusted EBITDA Contribution ~ 8% ~92%

4

PLAINS ALL AMERICAN PIPELINE, L.P.

PAA Recent Profile

PAA Aggregate Size/Yield

Total Assets [A]	$14.4 B
Book Equity [A]	$ 5.5 B
Book Cap. [A]	$10.0 B
Enterprise Value [AB]	$15.9 B
Equity Market Cap. [B]	$ 11.4 B
Fortune 500 Rank (revenues)	99
Unitholders	~134,000
Current Yield [B] ($4.10 annualized)	~5.6%

Public Guidance – Midpoint

2011 Adjusted EBITDA [C]	$1,538 MM
2011 Adj. Net Income [C]	$965 MM

Assets [(1)]

Pipelines (active miles)	~16,000 miles
Liquids Storage	~90 MMBbls
Natural Gas Storage [(2)]	~71 Bcf
LPG Railcars	~1,400
Truck Fleet	~585 Trucks ~960 Trailers
Barge Fleet (Settoon)	~65 Barges ~39 Tugs
Crude, Product & LPG Volumes:	~3.0 MMBbl/d

(1) Includes owned or leased assets as of 12/31/10, plus assets owned by PAA Natural Gas Storage ("PNG") (excludes leased natural gas storage capacity). Values may be approximated. Barge/Tug ownership through 50% interest in Settoon Towing.

(2) Average 2011 working gas capacity based on PNG guidance furnished via Form 8K on November 2, 2011.

A. Based on balance sheet data as of 9/30/11.
B. Based on 01/10/2012 closing unit price; excludes value of GP.
C. Adjusted EBITDA and Adjusted Net Income Attributable to Plains, (which has been abbreviated as "Adjusted Net Income"), are the midpoint of PAA's public guidance furnished via form 8-K on November 2, 2011 and exclude selected items impacting comparability. Excludes impact of expected over performance discussed in 12/1/11 press release.

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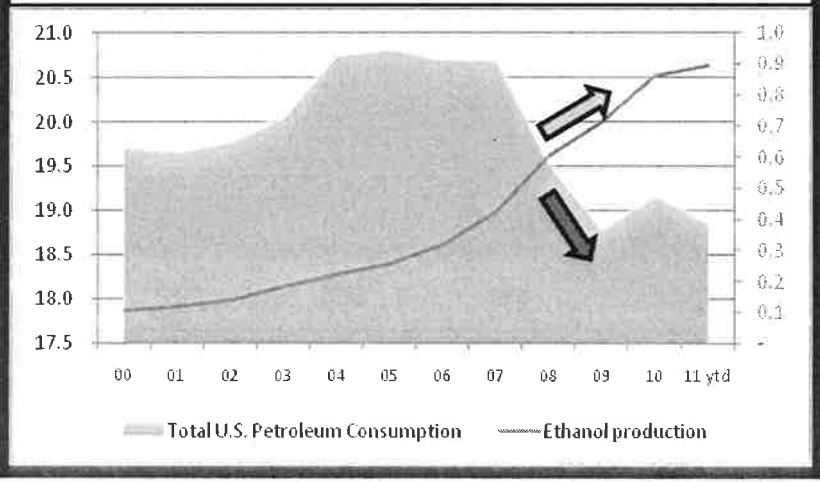
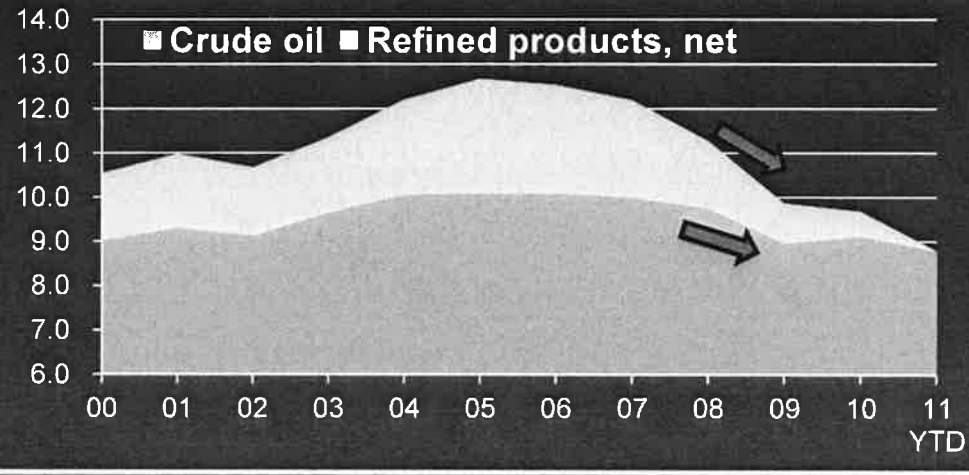
Macro U.S. Petroleum Trends

Recent Trends in U.S. Supply and Demand
Volumes in mmb/d

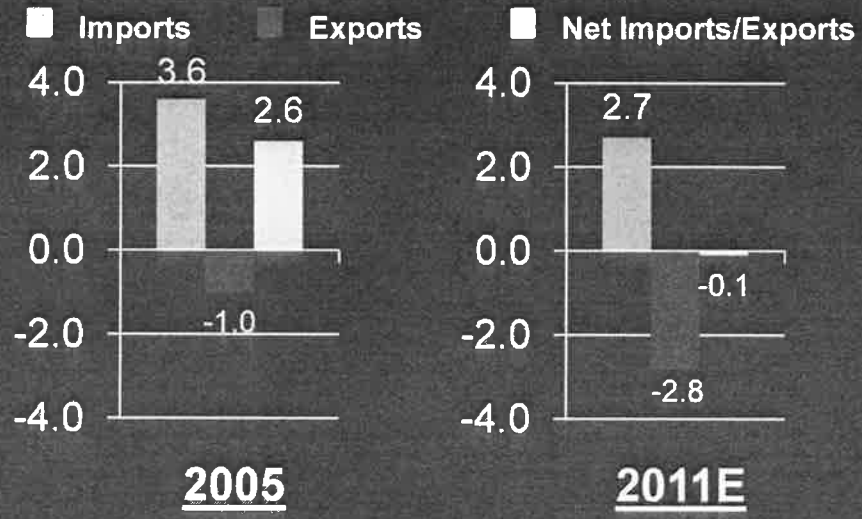
Declining Petroleum Consumption, Increasing Ethanol



Crude Oil Imports Declining; Refined Products at Crossover Point



Refined Products Import/Export Balance



Net change of ~2.7 mmbls/day

Source: EIA/DOE; Partnership estimates

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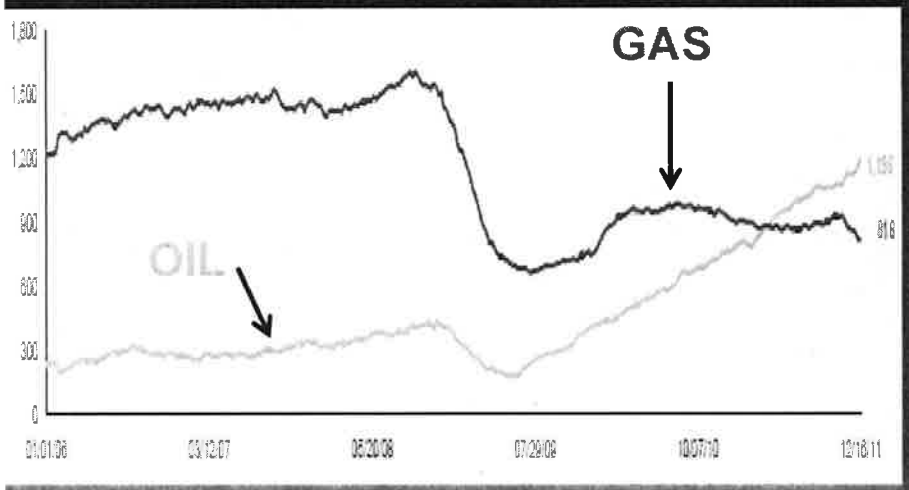
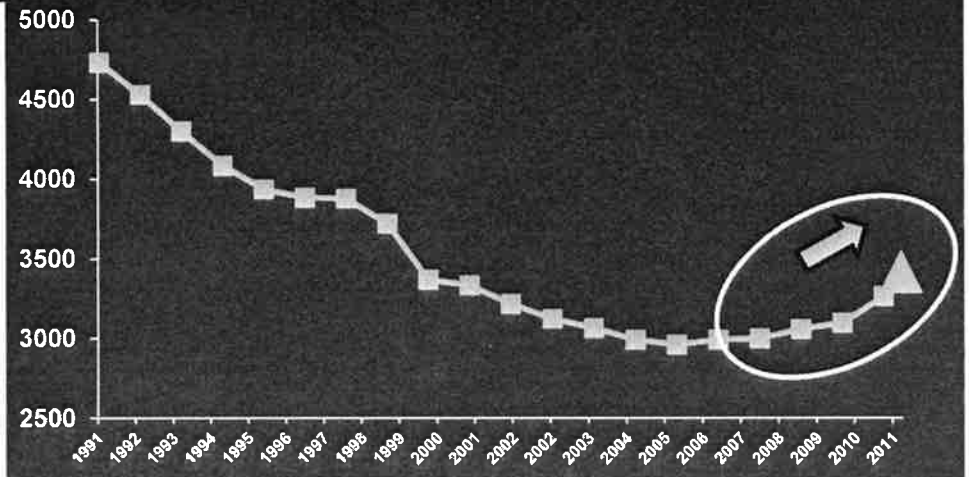
Emphasis Has Shifted From Gas to Oil Drilling With Nearly 50% of All Drilling Activity Focused In Three Key Areas



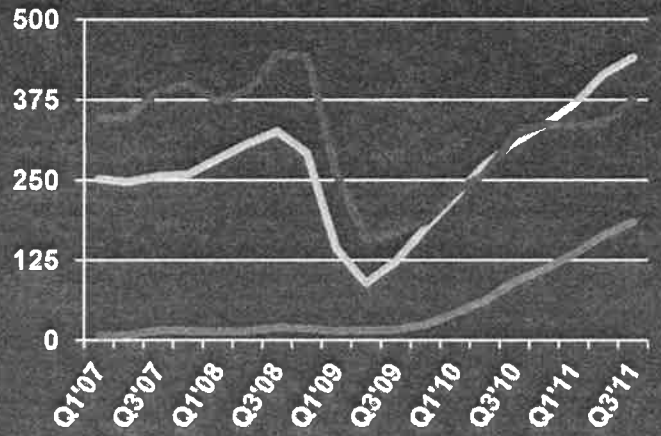
Lower 48 Domestic Crude Oil Production, Excludes Federal Offshore (mmb/d)



2011 Figure = Daily production YTD May, Annualized

Source : EIA

Rig Count (1)



- W. TX & NM
- Rockies
- Eagle Ford

Factors Contributing to U.S. Production growth

- ✓ Large acreage positions in resource plays
- ✓ Technological advancements in horizontal drilling & fracing
- ✓ Healthy liquids prices & supportive capital markets

(1) Source: RigData, Tudor Pickering Holt; Rig counts include both oil and gas.

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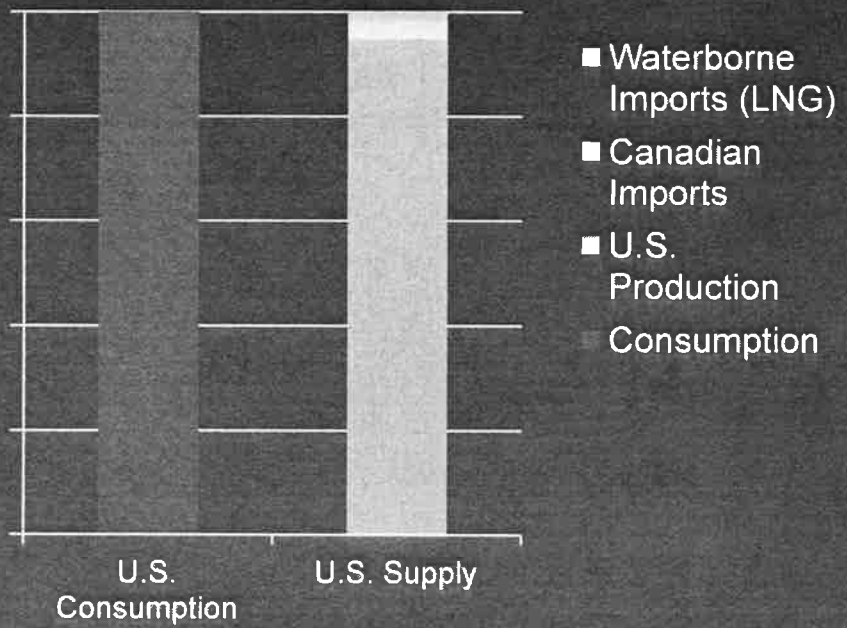
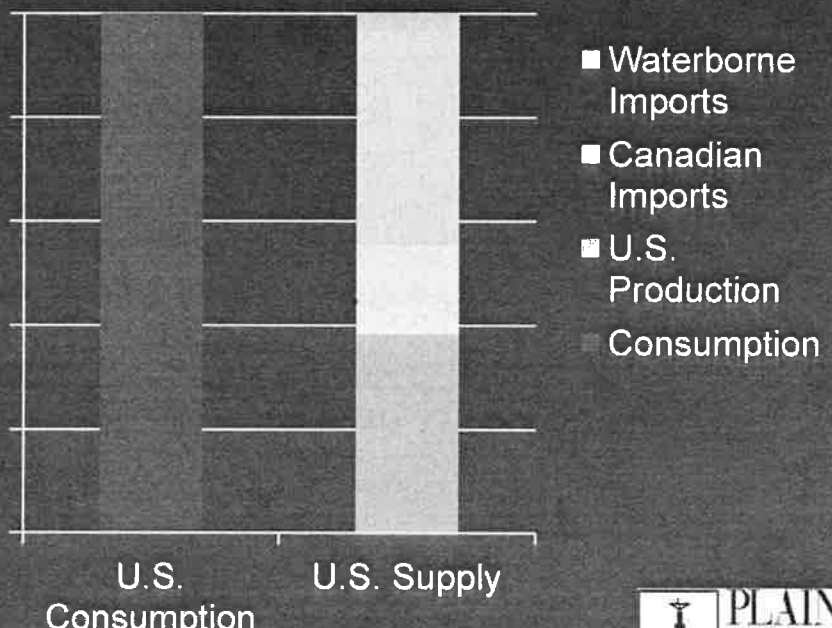
Increased U.S. Oil Production As Contrasted to Increased U.S. Natural Gas Production

- The significant increase in U.S. Natural Gas Production had a meaningful negative impact on gas prices
- Will an increase in U.S Crude Oil Production have a similar impact?
  - ✓ Unlikely, but it can (and likely will) impact quality and regional-location differentials (discussed later in the presentation)

U.S. Natural Gas Balances



U.S. Crude Oil Balances



Source: EIA/DOE. Balances are notional representations.

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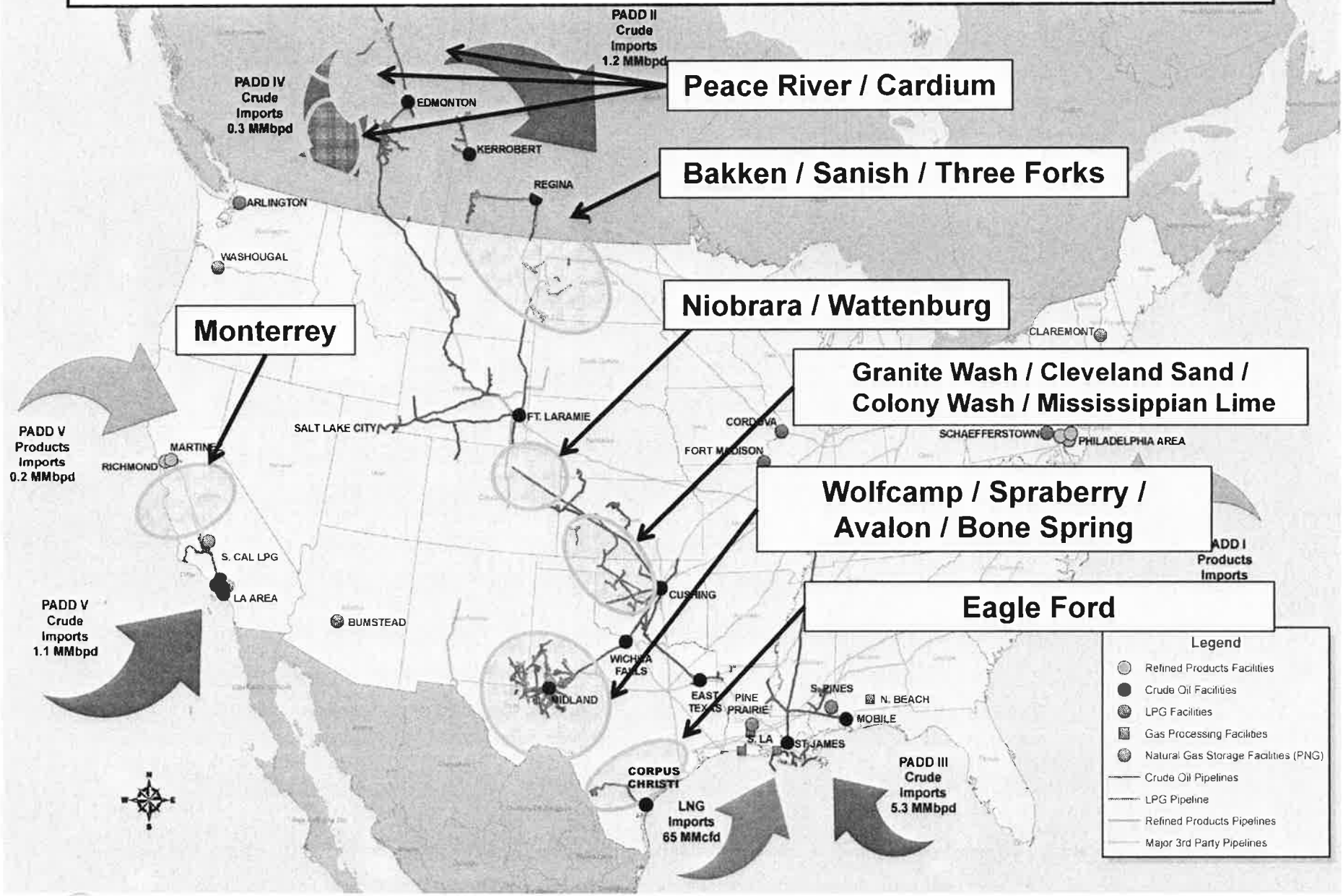
PAA's Assets are Very Well Positioned In Most North American Crude Oil Resource Plays



Challenges Associated with Rapid Development of Liquids Rich Shale/Resource Plays

Regional Infrastructure Challenges Related to Rapid Production Growth From Shale/Resource Plays

- Competitive/secret nature of producer activities understandably inhibits advance construction
  - ✓ acreage positions; resource capture; technology refinement, etc.
- Variation in results & identifying sweet spots delays design and construction of assets at optimal locations
- Uncertainties regarding ultimate size of aggregate production & sustainability
  - ✓ Producers are often willing to commit millions on acreage and drilling, but hesitant to make long-term transportation commitments
  - ✓ Pace of development often fluctuates with commodity prices
- Delayed producer decisions caused by competing proposals from multiple service providers

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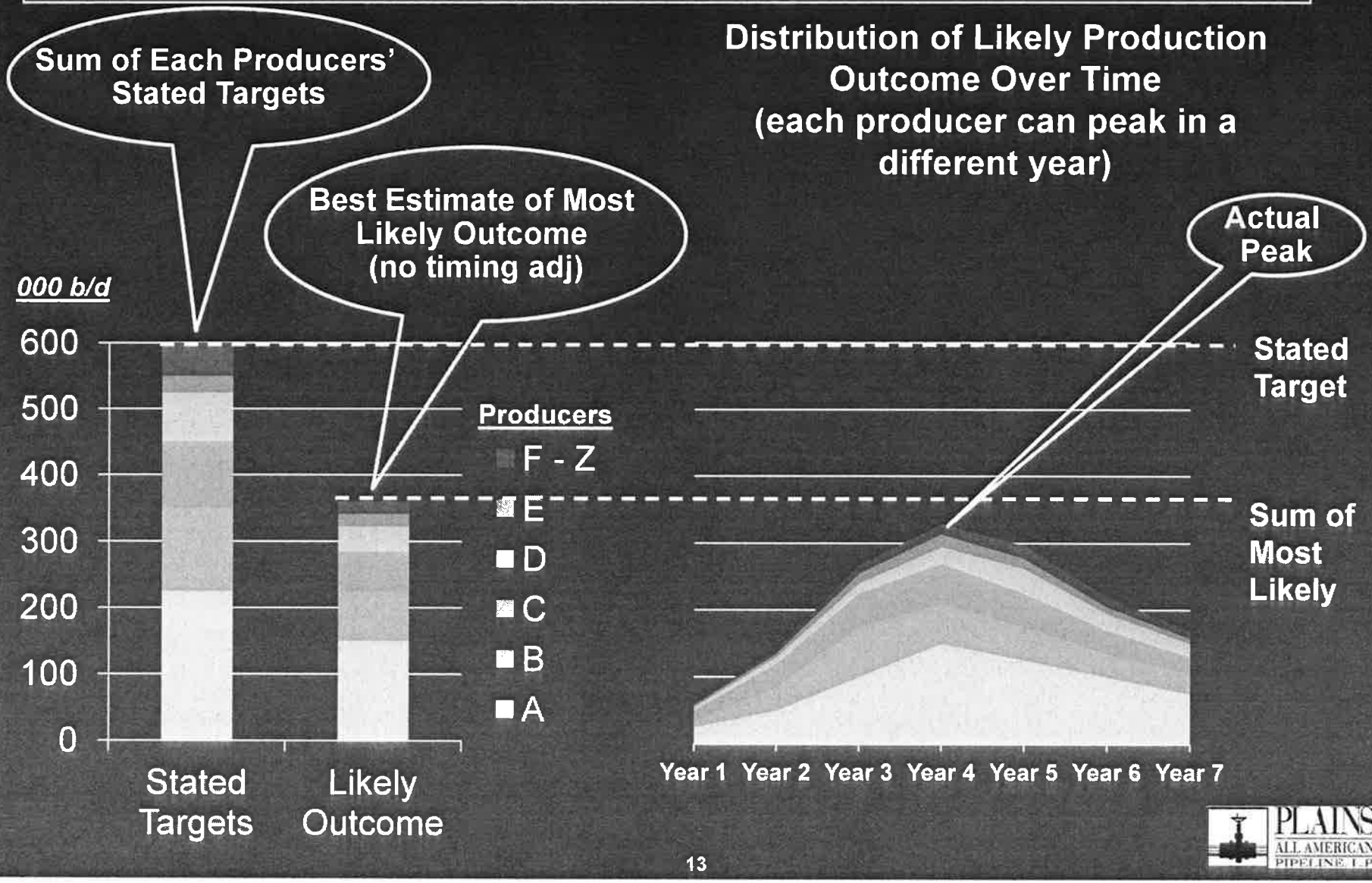
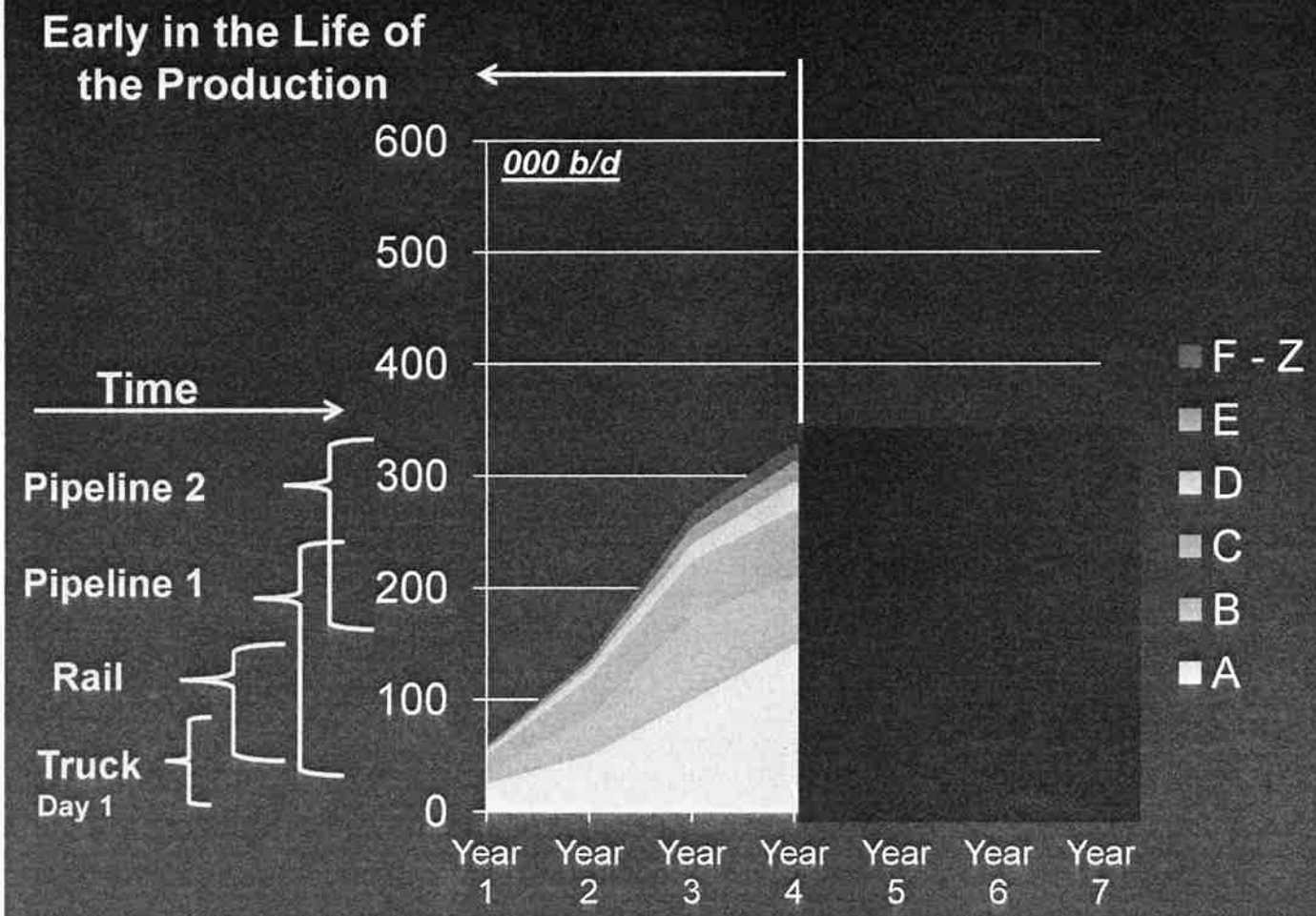
Right Sizing Long-Term Transportation Alternatives Is A Challenging Process



Conceptual Illustration of Transportation Methods Over Time



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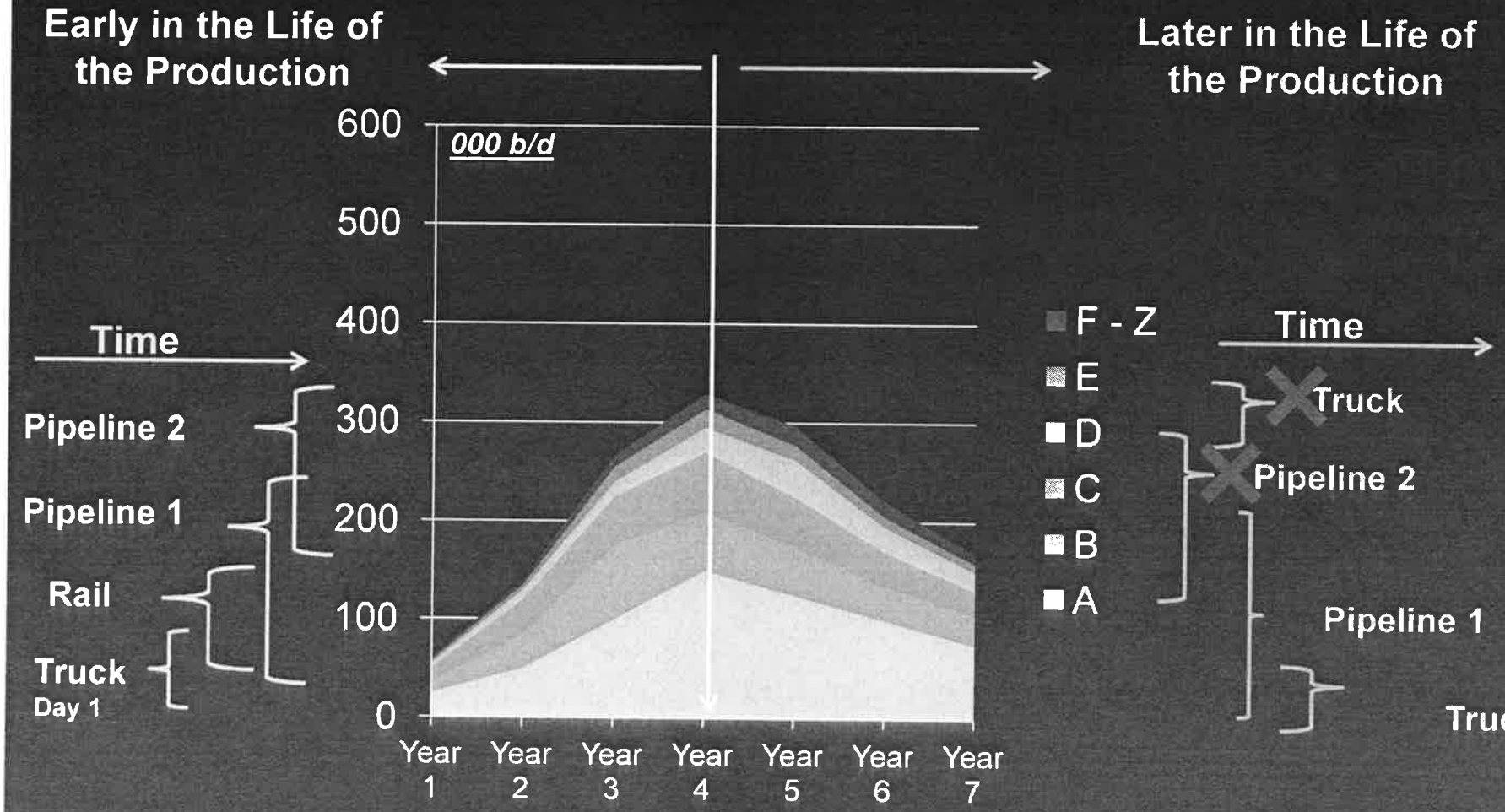
Conceptual Illustration of Transportation Methods Over Time



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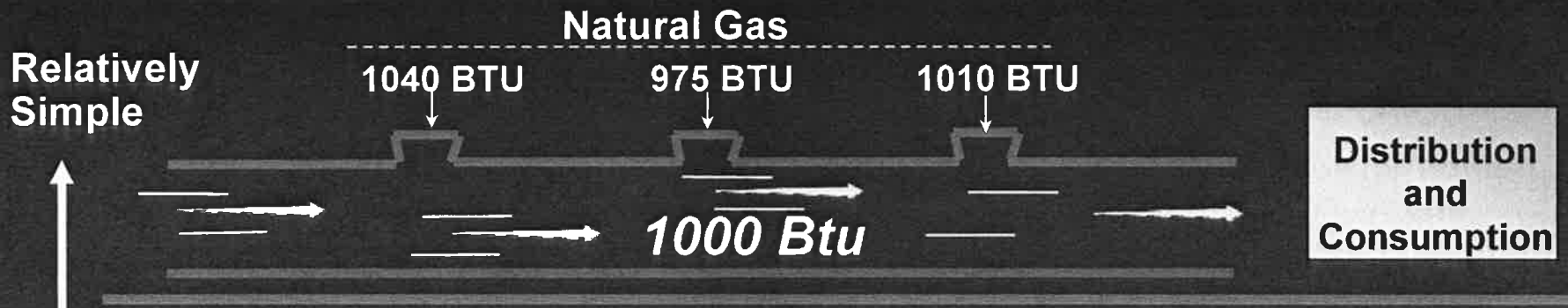
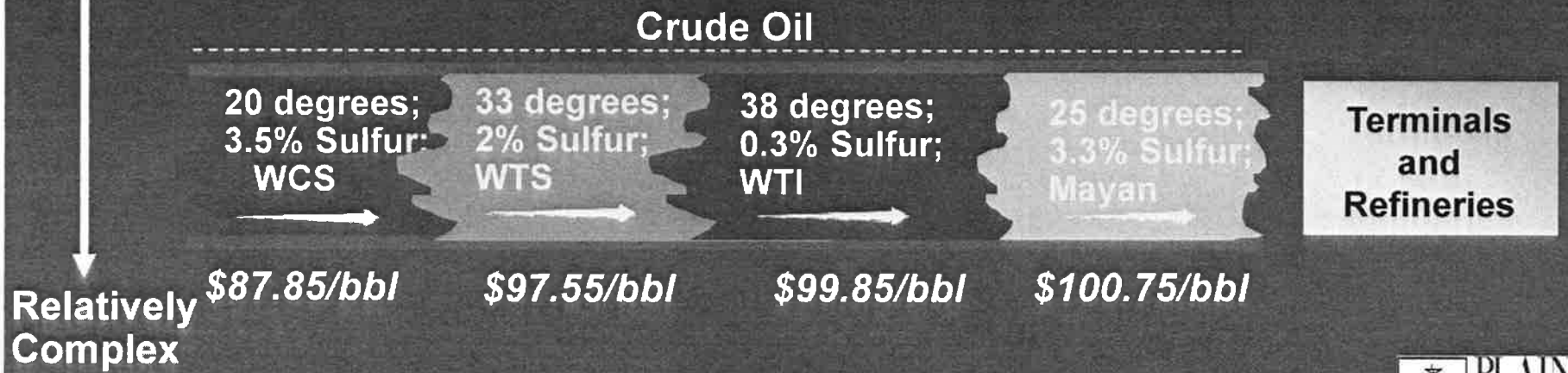
Crude Oil Qualities and Values Vary Significantly and Pose Transportation and Terminalling Challenges

In General, Transporting Crude Oil is Much More Complicated than Natural Gas



Multiple grades require multiple tanks at the pipeline origination, pipeline termination and certain locations along the pipeline for segregation, staging, batching and blending.



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Examples of Crude Types Handled by PAA at Its Pipeline and Terminal Facilities

Domestic / Canada

Sweet	Sour
DJ Condensate	W. Tx. Sour
Jameson	Poseidon
Spraberry	Mars Blend
Scurry	Okla. Sour
W. Tx. Int.	West Coast OCS
Okla. Sweet	Sunniland
Okla. Int.	W. Central TX
Kansas Sweet	Quitman Sour
N. TX Sweet	San Joaquin Light
East TX Sweet	San Joaquin Heavy
Light LA Sweet	Eugene Island
Heavy LA Sweet	Bonita
Mixed Sweet Blend	N. Dakota Light
Condensate Blend	W. Canadian Select
Syncrude Synthetic	Lloyd Blend Kerrobert
Suncor Synthetic A	Fosterton
	Cold Lake

Foreign

Sweet	Sour
Bonny Light	Mesa 30
Brent	Oriente
Brass River	Maya
Oseburg	Arab Medium
Gullfaks	Furiel
Cano Limon	Leona 24
Cabinda	Arab Heavy
Forties	Mesa 28
N'Kossa	Lago Cinco
Kissanje	Olmeca
Saharan Blend	Basrah
Oso	Roncador
Cusiana	Cano Limon
Doba	Calypso
Quaiboe	BCF 17
Zafiro	Hungo

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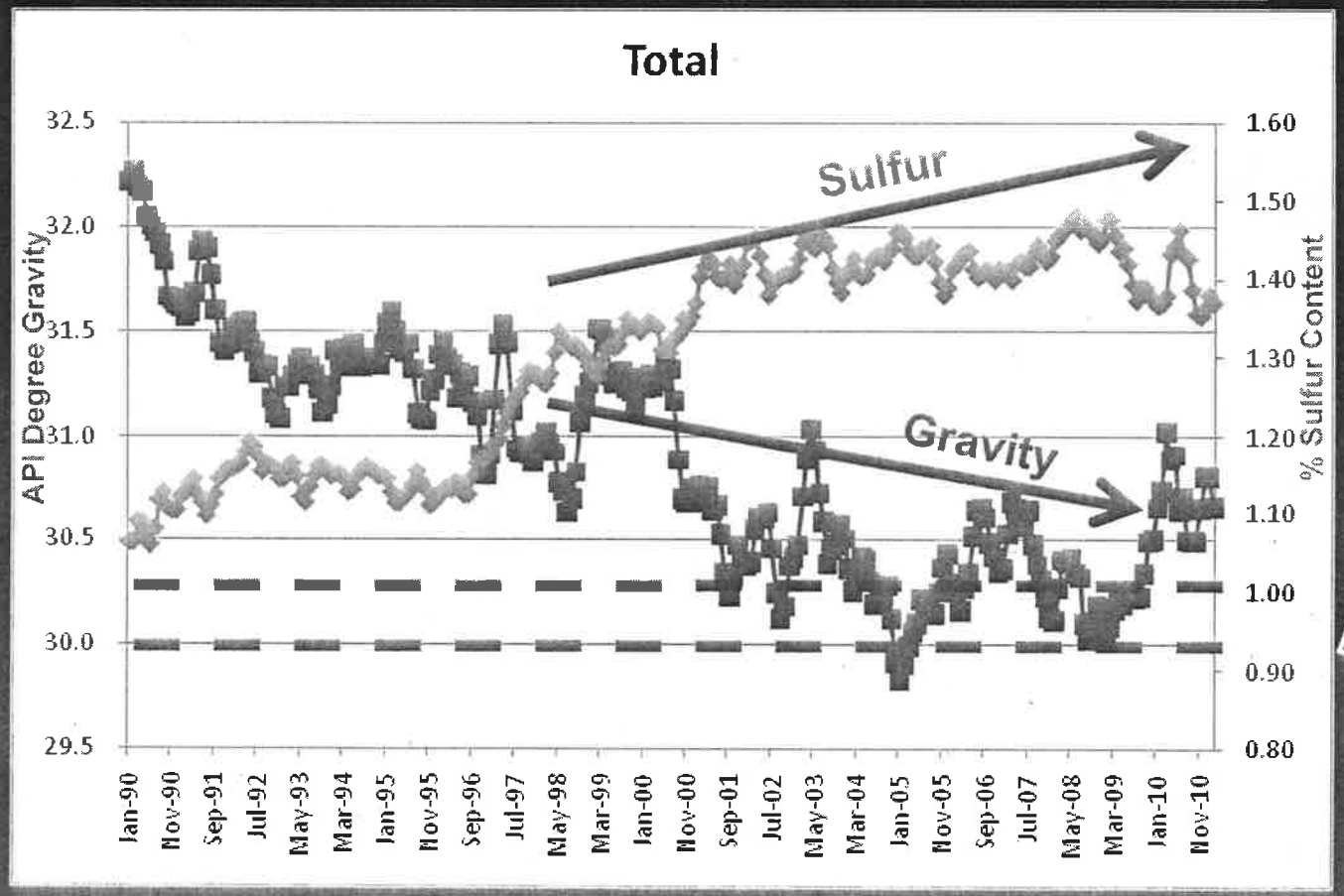
Aggregate U.S. Refinery Inputs Have Been Migrating Towards Higher Sulfur and Lower Gravity…

Over the Past Several Years, US Refiners Have Invested Billions to Be Able to Refine Increasingly Heavy & Sour Crudes



Gravity — 30° Gravity

Sulfur — 1% Sulfur

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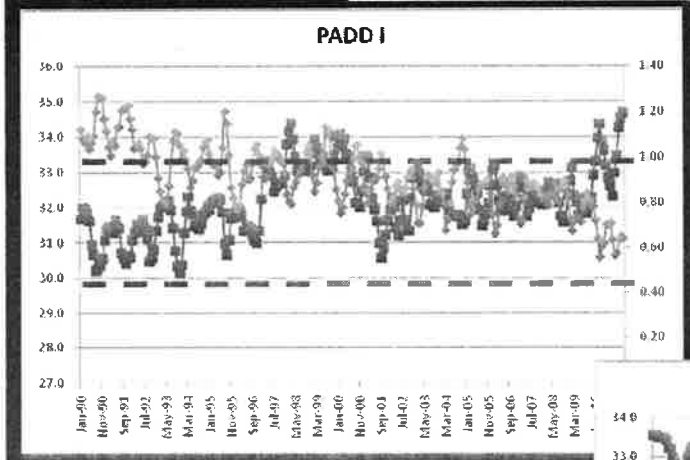
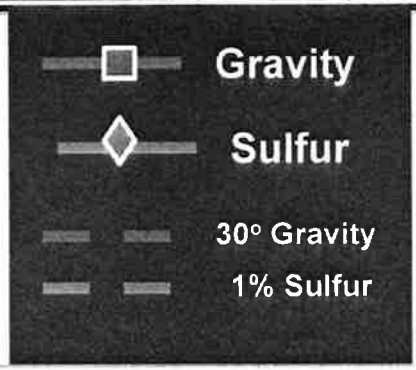
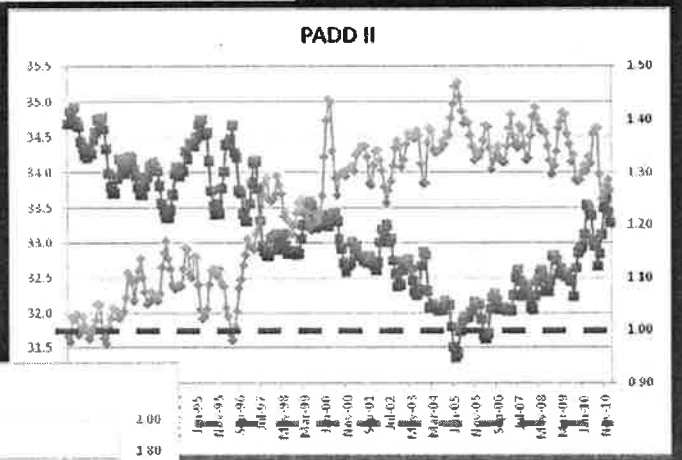
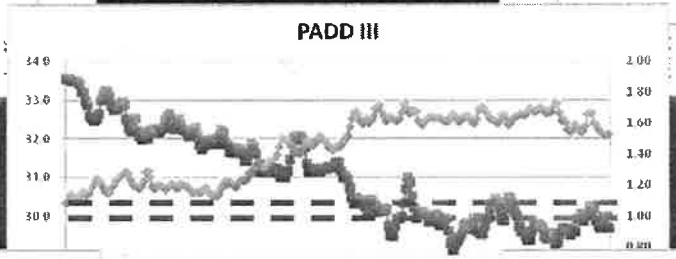
...But, Regional Crude Slates & Trends Vary Significantly

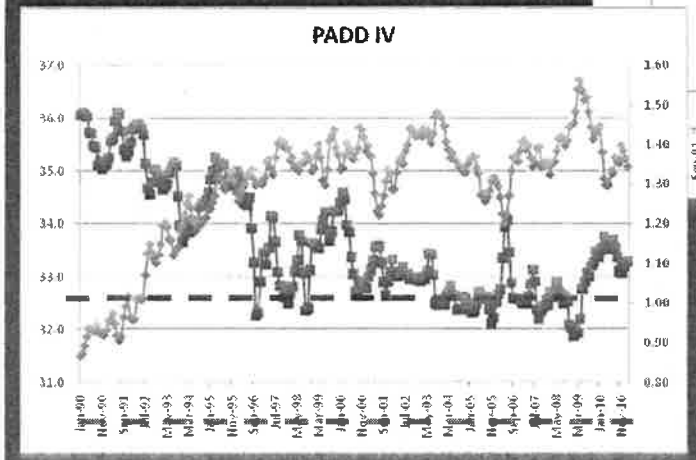
Increases the Need for More and Longer Movements

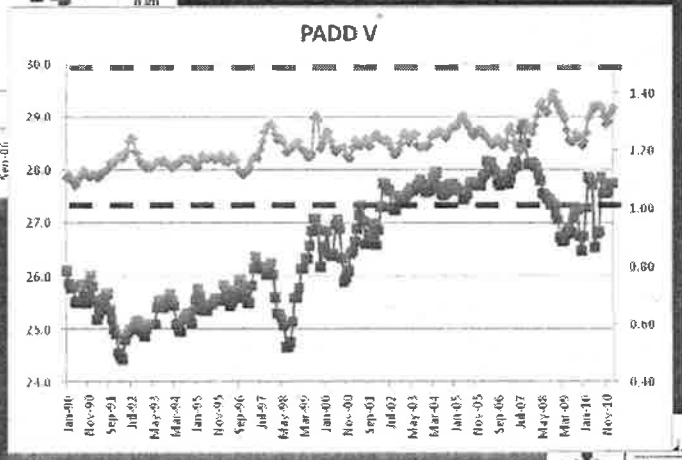










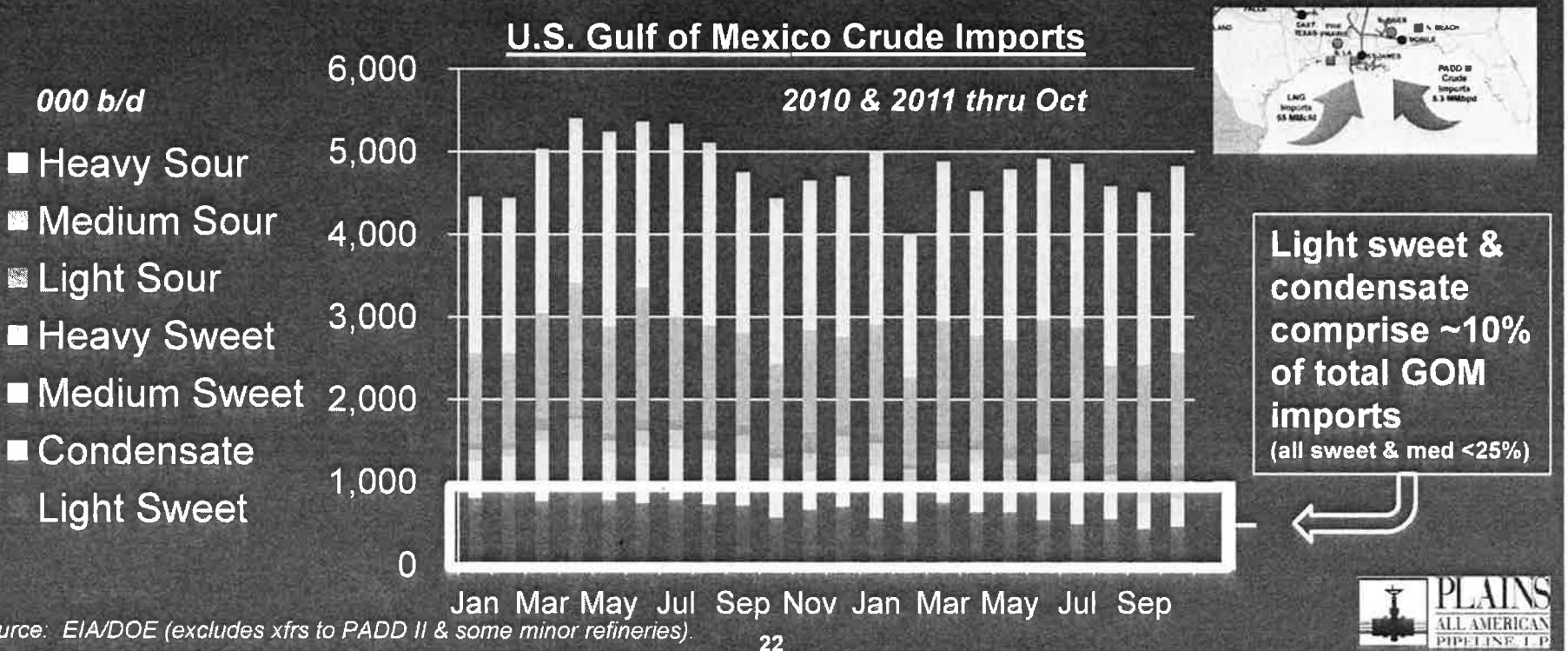


Regional Production Increases are Affecting Supply/Demand Dynamics of Crude Grades

- Refiners have spent Billions $$$ over last 5+ years to enhance their ability to process heavier, sour crudes
- Much of lower 48 increased crude oil production is light and sweet and, in many cases, is outstripping local demand
- Crude supply is also exceeding take-away capacity in certain areas
  - ✓ Eagle Ford and Bakken plays currently lack adequate pipeline infrastructure
  - ✓ West Texas and Mid-Continent areas require additional investment including expanding existing assets (adding pumping capacity, looping pipelines), construction of extensions to existing systems and (in some cases) new-build of main-line capacity
- Pipeline bottlenecks (real or perceived) in Cushing are contributing (or have contributed) the widening of WTI – LLS – Brent differentials

Prevailing Perception Is That Domestic Light Sweet Will Back Out Waterborne Foreign Imports in GOM

- Reality is that the vast majority of foreign imports into the GOM are sour or heavy barrels by design
  - ✓ Some foreign streams are under long term contracts
- Prices for "Excess" light sweet barrels will be adjusted to displace heavier or sour barrels
  - ✓ Unlike refined products, export of domestic crude oil is not permitted



Light sweet & condensate comprise ~10% of total GOM imports
(all sweet & med <25%)

Source: EIA/DOE (excludes xfrs to PADD II & some minor refineries).

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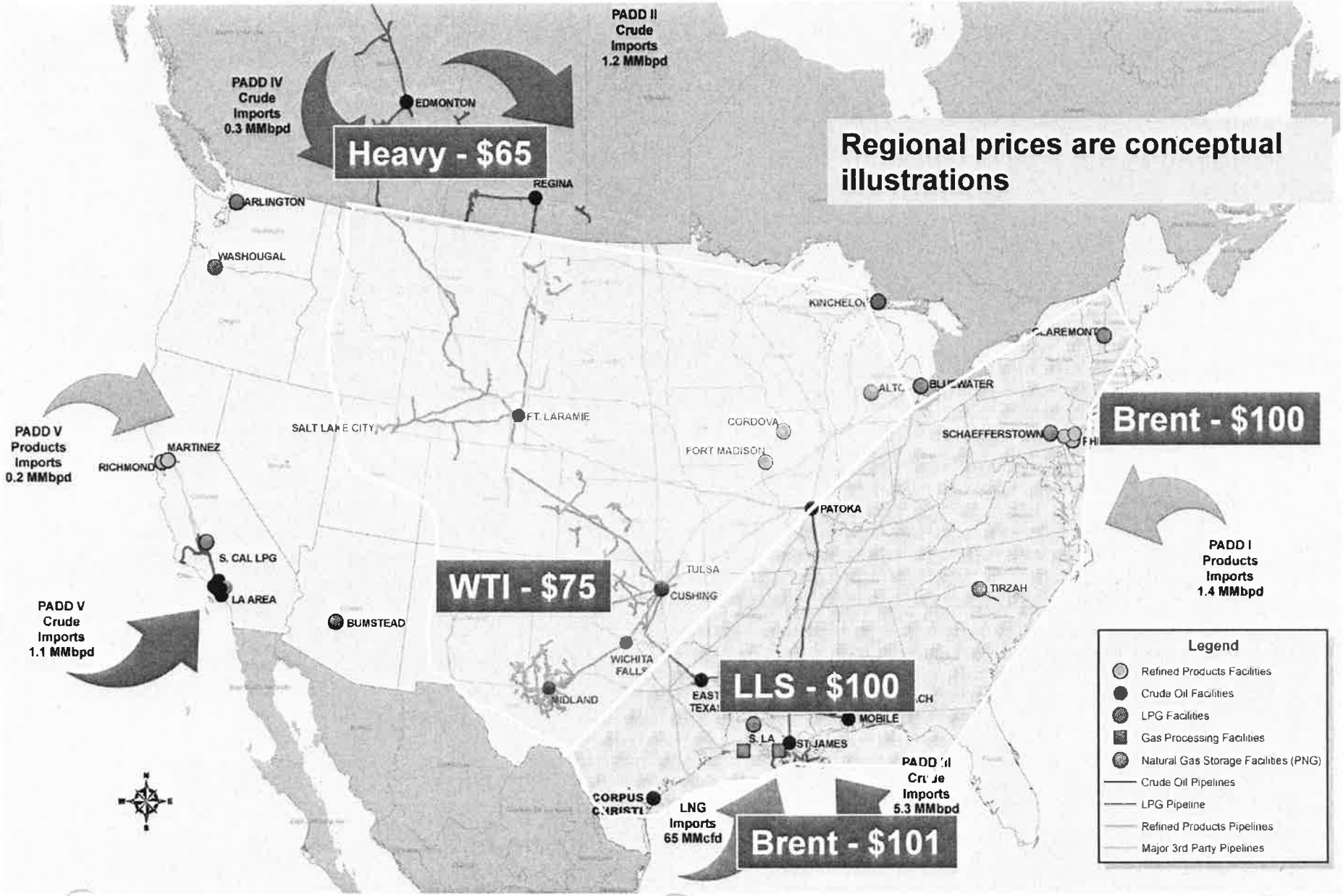
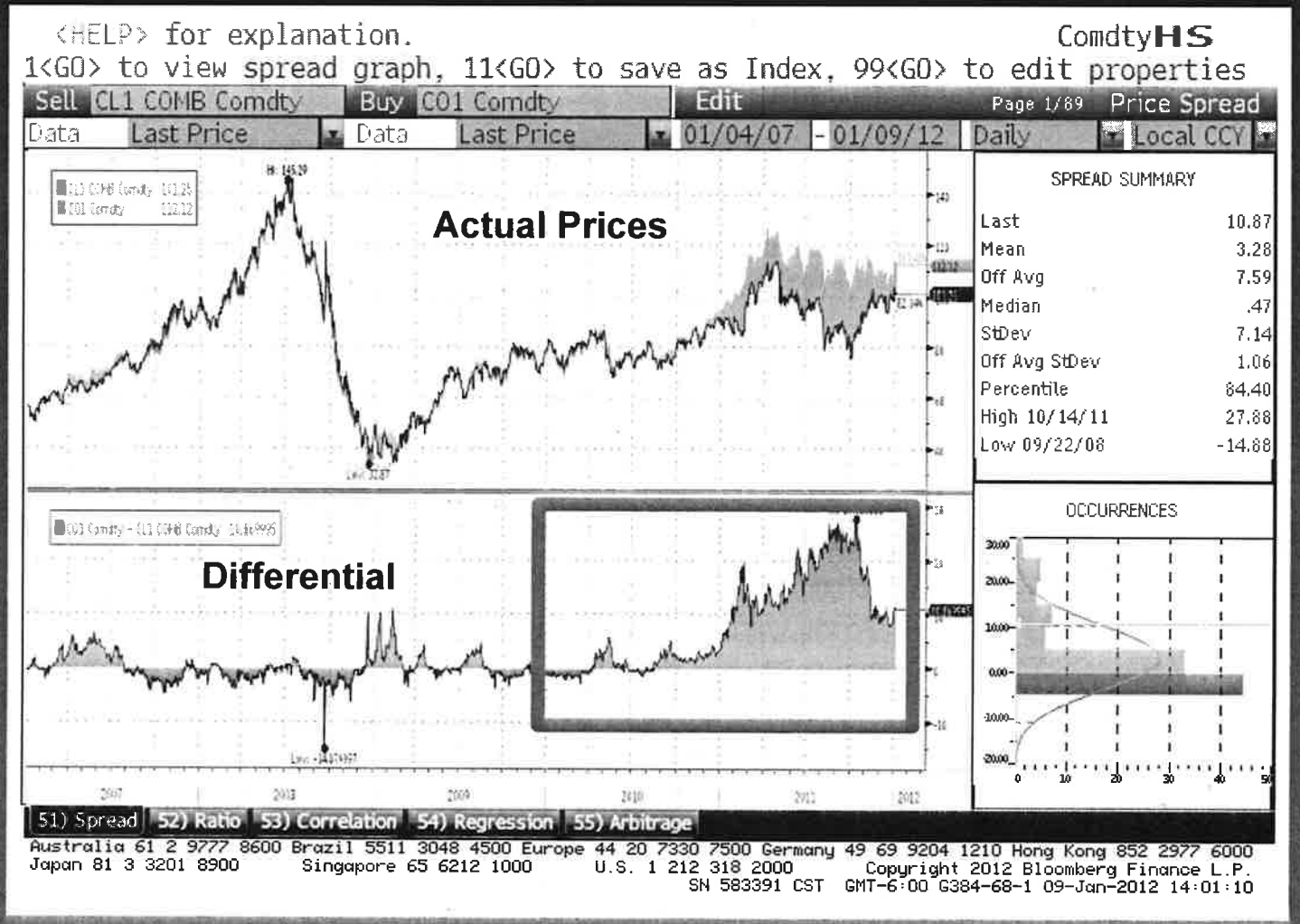
WTI Brent Differential

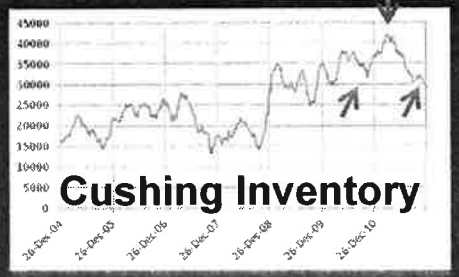
Snapshot in Time: October 2011



5 year WTI Brent Differential



Multiple Factors Contributed to Widening of WTI to Brent Differential

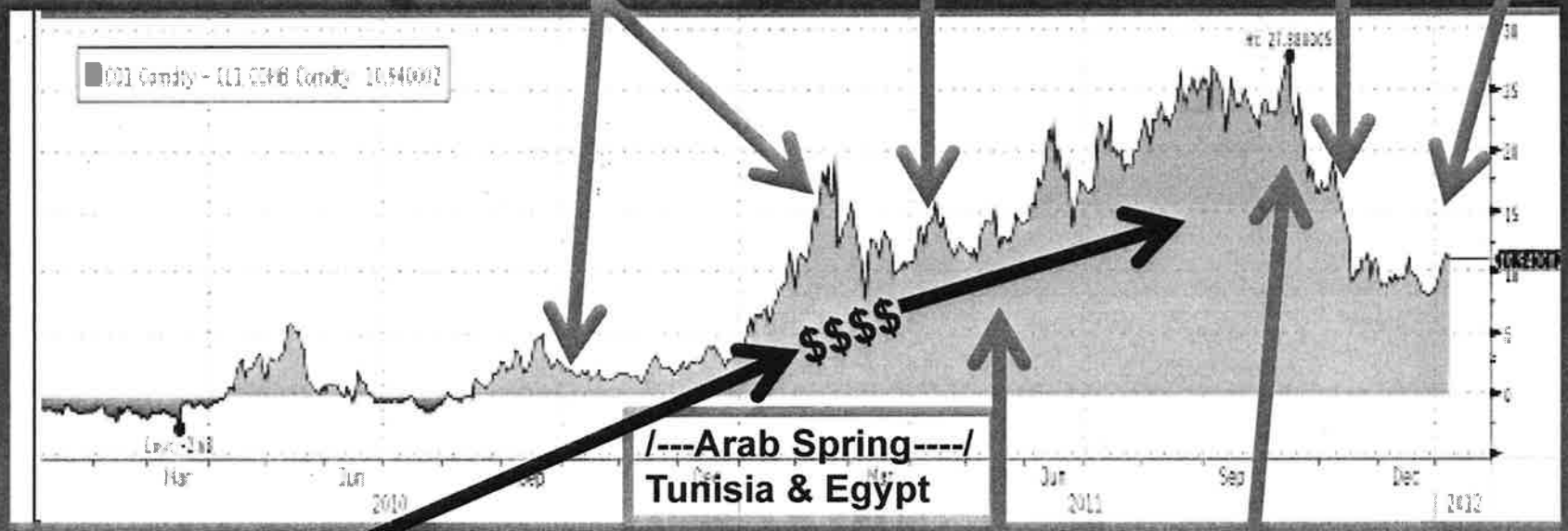


Cushing Inv. Rises ~25% ~32 mmbls to ~40 mmbls

Peak Cushing Inventory 41.9mmbls

Seaway Reversal Announced

Recent Cushing Inv. 29.3 mmbls



Commodities Money Flows Favored Brent vs WTI
-- Pronounced contango in WTI
-- Lesser contango in Brent

Unrest rolls across to N. Africa & Libya

Gadhafi "Removed"

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Selected Thoughts on 2012

(assuming no drilling or disposal bans relative to fracing)

- Crude oil:
  - ✓ Flat prices will be very volatile, but generally robust
  - ✓ Regional/location differentials will increase/decrease in fits and starts
  - ✓ Quality differentials will be volatile and challenge conventional wisdom
- Natural Gas:
  - ✓ The strip price will remain unexciting
  - ✓ Absent abnormally cold weather & meaningful inventory draws, storage capacity will be tested in 2012
    - ✓ Cash market may see significant discounts to Nymex pricing
    - ✓ Differentials will widen in certain regions
  - ✓ Industrial & commercial demand will begin to revive

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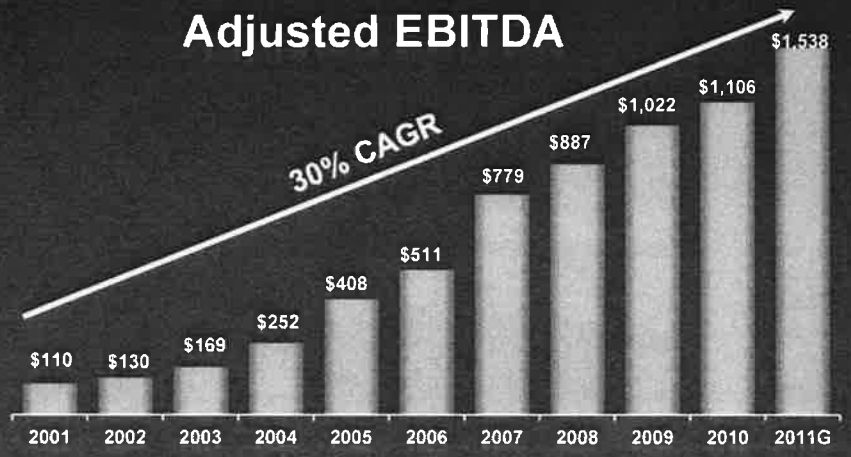
...Now for the Shameless PAA Advertisement

PAA Has A Long Track Record of Delivering Solid Distribution Growth and Attractive Total Returns

Adjusted EBITDA

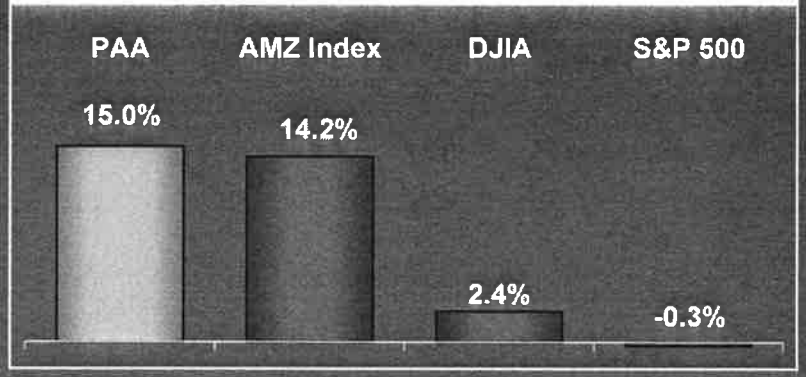


Note: EBITDA in graph excludes the impact of selected items impacting comparability, 2011 EBITDA guidance based on midpoint provided in Form 8-K furnished on November 2, 2011.

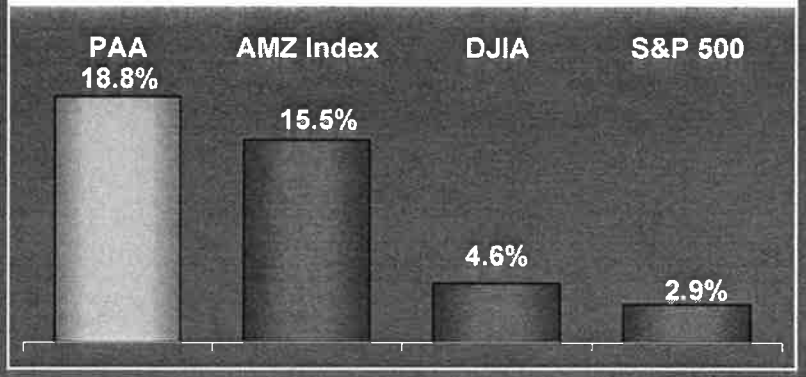
Distributions

(1)Distribution levels represented are annualized run-rate distributions as of the Nov distribution of each year . Growth rate calculated on actual quarterly distributions from 1Q01 through 4Q11.

5-Yr Annualized Total Return



10-Yr Annualized Total Return



Source: Bloomberg (Total Return function)

*Annual Total Returns based on trailing five and ten year periods ended 12/31/11.

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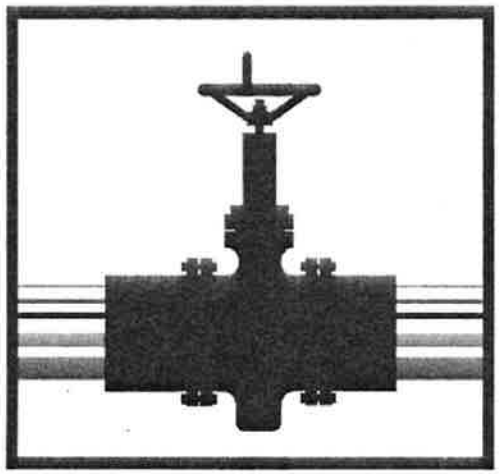

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Additional 8-K(1) Reconciliations-Conference Call

(In millions, except per share amounts)

Net Income to EBITDA Reconciliations

Reconciliation of Net Income to Adjusted EBITDA (2002 - 2005)	2002					2003					2004					2005				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD
Net income	$ 14	$ 17	$ 18	$ 16	$ 65	$ 24	$ 23	$ 12	$ (20)	$ 39	$ 33	$ 38	$ 42	$ 25	$ 138	$ 33	$ 62	$ 63	$ 54	$ 212
Interest expense	7	8	7	8	30	9	9	9	9	36	10	10	11	15	46	15	14	14	15	58
EBIT	21	25	24	27	94	34	32	21	9	96	37	48	54	39	177	47	77	85	69	277
Depreciation and amortization	7	7	9	11	34	11	11	12	12	46	13	15	16	23	68	18	19	20	28	84
EBITDA	$ 28	$ 31	$ 33	$ 38	$ 129	$ 44	$ 43	$ 33	$ 21	$ 141	$ 50	$ 63	$ 70	$ 62	$ 245	$ 65	$ 96	$ 105	$ 97	$ 361
Selected items impacting comparability of EBITDA[2]																				
Gains/(losses) from other derivative activities	$ (3)	$ 1	$ -	$ 2	$ -	$ 1	$ -	$ (2)	$ 2	$ -	$ 6	$ (1)	$ 1	$ (1)	$ 5	$ (13)	$ (13)	$ 6	$ 1	$ (19)
Equity compensation expense	-	-	-	-	-	-	-	(7)	(22)	(29)	(4)	-	-	(4)	(8)	(2)	(6)	(7)	(9)	(24)
Net gain/(loss) on foreign currency revaluation[3]	-	-	-	-	-	-	-	-	-	-	(1)	1	3	2	4	(1)	1	(2)	(1)	(3)
Cumulative effect of change in acct. principle	-	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(3)	-	-	-	-	-
Other	-	-	-	(2)	(2)	-	-	-	-	-	-	-	-	(2)	(2)	-	-	-	-	-
Total selected items impacting comparability of EBITDA	$ (3)	$ 1	$ -	$ -	$ (2)	$ 1	$ -	$ (9)	$ (20)	$ (29)	$ -	$ (8)	$ 4	$ (5)	$ (7)	$ (16)	$ (18)	$ (3)	$ (9)	$ (46)
Adjusted EBITDA	$ 31	$ 29	$ 33	$ 36	$ 131	$ 42	$ 43	$ 42	$ 40	$ 169	$ 50	$ 55	$ 67	$ 67	$ 252	$ 81	$ 115	$ 107	$ 106	$ 407

Reconciliation of Net Income to Adjusted EBITDA (2006 - 2009)	2006					2007					2008					2009				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD
Net income	$ 85	$ 80	$ 95	$ 46	$ 306	$ 85	$ 126	$ 92	$ 77	$ 385	$ 92	$ 41	$ 205	$ 96	$ 433	$ 211	$ 136	$ 122	$ 110	$ 580
Income tax expense (benefit)	-	-	-	-	-	-	12	2	1	15	(2)	5	3	1	8	1	(2)	2	5	6
Interest income	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest expense	15	16	19	32	82	41	41	38	41	161	42	49	62	50	203	51	56	59	58	224
EBIT	79	96	115	78	370	126	179	140	119	542	132	95	261	152	641	263	190	183	173	810
Depreciation and amortization	22	24	24	33	103	40	42	42	46	170	48	52	49	61	211	58	58	59	61	236
EBITDA	$ 100	$ 120	$ 139	$ 112	$ 473	$ 166	$ 219	$ 183	$ 164	$ 732	$ 180	$ 147	$ 310	$ 213	$ 852	$ 321	$ 248	$ 242	$ 235	$ 1,046
Selected items impacting comparability of EBITDA[2]																				
Gains/(losses) from other derivative activities[4]	$ (1)	$ (2)	$ 18	$ (19)	$ (4)	$ (17)	$ 15	$ (14)	$ (2)	$ (18)	$ (9)	$ (57)	$ 94	$ 4	$ 32	$ 28	$ 15	$ 11	$ (33)	$ 21
Inventory valuation adjustments net of gains/(losses) from related derivative activities[4]	-	-	-	-	-	-	-	-	-	-	-	-	4	(16)	(11)	22	1	-	-	23
Equity compensation benefit/(expense)	(11)	(5)	(10)	(16)	(42)	(16)	(19)	(1)	(6)	(44)	(6)	(15)	(3)	2	(21)	(9)	(15)	(12)	(14)	(50)
Net gain/(loss) on foreign currency revaluation[3]	-	-	-	-	-	-	-	-	-	-	-	-	(4)	(13)	(21)	10	2	-	-	12
Cumulative effect of change in acct. principle	6	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gains on Brazilian acquisition-related foreign currency and commodity hedges	-	-	-	-	-	-	-	-	-	-	-	11	-	-	11	-	-	-	-	-
Net loss on early repayment of senior notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	(4)
Net gain on purchase of remaining 50% interest in PNGS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	9
Gains/(losses) on sale of assets	-	-	-	-	-	-	-	-	12	12	-	-	-	-	-	-	-	-	-	-
Net loss on early repayment of 7.125% $225 million senior notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PNGS contingent consideration fair value adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
Total selected items impacting comparability of EBITDA	$ (6)	$ (7)	$ 8	$ (35)	$ (41)	$ (33)	$ (4)	$ (14)	$ (3)	$ (55)	$ (11)	$ (61)	$ 87	$ (23)	$ (39)	$ 49	$ 3	$ 8	$ (39)	$ 21
Adjusted EBITDA	$ 106	$ 128	$ 131	$ 146	$ 511	$ 201	$ 214	$ 197	$ 167	$ 779	$ 191	$ 208	$ 223	$ 236	$ 857	$ 272	$ 240	$ 234	$ 235	$ 1,027

Reconciliation of Net Income to Adjusted EBITDA (2010 - 2011)	2010					2011				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD
Net income	$ 151	$ 153	$ 34	$ 146	$ 514	$ 165	$ 233	$ 283	$ -	$ 709
Income tax expense (benefit)	-	-	(4)	3	(1)	13	9	6	-	28
Interest expense	58	52	64	64	248	65	62	60	-	187
EBIT	209	205	144	213	761	243	304	349	-	924
Depreciation and amortization	67	54	61	64	246	62	53	65	-	181
EBITDA	$ 276	$ 259	$ 205	$ 277	$ 1,017	$ 305	$ 357	$ 423	$ -	$ 1,105
Selected items impacting comparability of EBITDA[2]										
Gains/(losses) from other derivative activities	$ 19	$ 21	$ (42)	$ (32)	$ (14)	$ 29	$ 21	$ 31	$ -	$ 72
Equity compensation benefit/(expense)	(14)	(9)	(10)	(32)	(65)	(14)	(20)	(7)	-	(40)
Net loss on early repayment of senior notes	-	-	(8)	-	(8)	(23)	-	-	-	(23)
Acquisition-related expenses	-	-	-	-	-	(4)	-	-	-	(4)
PNGS contingent consideration fair value adjustment	(1)	(1)	(1)	-	(3)	-	-	-	-	-
Insurance deductible reversal to property damage accident	-	-	-	-	-	(1)	-	-	-	(1)
Loss on foreign currency revaluation[3]	-	-	-	-	-	-	(17)	-	-	(17)
Total selected items impacting comparability of EBITDA	$ 4	$ 11	$ (59)	$ (65)	$ (89)	$ (23)	$ 1	$ 7	$ -	$ (13)
Adjusted EBITDA	$ 272	$ 248	$ 264	$ 322	$ 1,106	$ 348	$ 358	$ 414	$ -	$ 1,118

(1) Amounts may not recalculate due to rounding.

(2) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

(3) Currently included as a selected item impacting comparability in periods with significant activity.

(4) Beginning with the first quarter of 2005, gains and losses from derivative activities related to realized inventory are included in the line item "Inventory valuation adjustments net of gains/(losses) from related derivative activities." gains and losses from derivative activities not related to realized inventory are included in the line item "Gains/(losses) from other derivative activities."

Additional 9/30/11 Reconciliations - Midpoint Guidance
(in millions) [1]

Midpoint Guidance Adjusted Net Income attributable to Plains & Adjusted EBITDA to Net Income

	Mid-point Guidance [2]	
	3 Months Ending December 31, 2011	12 Months Ending December 31, 2011
Net Income	$ 265	$ 971
Net income attributable to noncontrolling interests	(7)	(25)
Net Income attributable to Plains	$ 258	$ 946
Selected Items Impacting Comparability - INCOME / (LOSS):		
Equity compensation expense	$ (9)	$ (49)
Gains from other derivative activities	-	72
Net loss on early repayment of senior notes	-	(20)
Loss on foreign currency revaluation	-	(17)
Other	-	(5)
Selected Items Impacting Comparability of EBITDA	(9)	(22)
Losses from other derivative activities	-	(1)
Selected Items Impacting Comparability of Net Income	(9)	(23)
Noncontrolling interest portion of Selected Items Impacting Comparability	1	4
Selected Items Impacting Comparability of Net Income attributable to Plains	$ (8)	$ (19)
Adjusted Net Income attributable to Plains	$ 266	$ 965
Interest expense	64	254
Income tax expense	9	37
Depreciation and amortization	63	254
Adjusted EBITDA	$ 410	$ 1,538

[1] Amounts may not recalculate due to rounding.

[2] Represents the mid-point of guidance furnished in our November 2, 2011 Form 8-K.

Western Canadian Select (WCS) fact sheet

Creating new benchmark crude

In conjunction with Canadian Natural Resources Limited, Suncor and Talisman Energy Inc., we have implemented a new heavy oil stream named Western Canadian Select (WCS).

WCS — produced out of Western Canada — is made up of existing Canadian heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents. It is a consistent high quality crude blend that was launched in December 2004 with volumes of approximately 250,000 barrels per day, and is well-positioned to become a North American benchmark.

A diverse Canadian oil market

There are approximately 25 separate heavy oil streams marketed out of Western Canada and this number continues to grow. The abundance of streams results in several inefficiencies. WCS offers an ideal solution:

Issue	25+ separate oil streams	WCS Solution
infrastructure	— requires more tankage which increases costs	— a blend of crudes reduces the number of streams — more effective use of existing tankage in the pipeline delivery systems out of Western Canada
Crude quality and consistency	— increases the risk of downstream quality deterioration due to mixing of varying grades in tanks en-route to market	— by virtue of its stream size, minimizes contamination caused by mixing of various grades — delivers more consistent quality to the buyer
Conventional diluent supply	— most Western Canadian heavy oil streams require diluent for transportation — as Canadian production continues to grow, the demand for diluent is expected to increase, yet the supply is expected to remain flat	— using sweet synthetic and condensate as a diluent reduces dependence on conventional diluent alone and improves reliability
Market liquidity	— a growing number of separate heavy oil streams results in reduced liquidity in any one stream, reducing crude acceptance and narrowing the ability for it to trade	— as a large stream of consistent quality crude, WCS can increase liquidity and should constitute a highly acceptable, more widely traded crude for producers and refiners alike

WCS Potential

West Texas Intermediate (WTI) and Brent are recognized as benchmark crudes. WCS has satisfied much of the criteria to become a benchmark. WCS has achieved threshold volumes of approximately 250,000 barrels per day and may grow from those numbers, whereas WTI and Brent are both declining from their current volume of about 350,000 barrels a day each. Furthermore, as a new benchmark, WCS is more effective than WTI as a means of financially hedging price risk against North American heavy oil grades because WCS addresses issues around product, price and location.

Benefits to producers and refiners

Producers: improved use of existing downstream pipeline facilities means that producers can deliver consistent quality crude with reliable on-time delivery to market. In addition, the improved stream liquidity will make WCS a more widely traded crude.

Refiners: refiners will have access to a stable, reliable and rateable crude, stringently monitored by the producing parties.

Our market development initiatives

To recognize the full value of Canadian crude oil, we are committed to:

- Creation of WCS, a new heavy oil steam benchmark that will provide greater operational efficiency; greater market reach; and greater liquidity.
- Developing new markets, such as the Southern mid-Continent, the Gulf of Mexico, and the West Coast, for heavy crude oil.
- Promoting the development of new heavy oil conversion projects in core markets.

WCS Crude Oil Quality

	WCS
Gravity (API)	20.5
Density (kg/m3)	930.1
MCR (Wt%)	9.6
Sulphur (Wt%)	3.51
TAN (Mg KOH/g)	0.93

Crude quality data from Crude Quality Inc. average for 2009.

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U.S. Energy Information Administration

Petroleum & Other Liquids

Company Level Imports

With Data for April 2013 | **Release Date:** June 27, 2013 | **Next Release Date:** July 30, 2013 |

Previous Issues

Month: April 2013 Go

April 2013 Import Highlights

Monthly data on the origins of crude oil imports in April 2013 has been released and it shows that two countries exported more than 1 million barrels per day to the United States (see table below). The top five exporting countries accounted for 75 percent of United States crude oil imports in April while the top ten sources accounted for approximately 94 percent of all U.S. crude oil imports. The top five sources of US crude oil imports for April were Canada (2,517 thousand barrels per day), Saudi Arabia (1,107 thousand barrels per day), Mexico (905 thousand barrels per day), Venezuela (811 thousand barrels per day) and Iraq (455 thousand barrels per day). The rest of the top ten sources, in order, were Colombia (440 thousand barrels per day), Nigeria (320 thousand barrels per day), Ecuador (310 thousand barrels per day), Kuwait (232 thousand barrels per day) and Angola (154 thousand barrels per day). Total crude oil imports averaged 7,726 thousand barrels per day in April, which is an increase of 266 thousand barrels per day from March 2013.

Canada remained the largest exporter of total petroleum in April; exporting 3,163 thousand barrels per day to the United States. The second largest exporter of total petroleum was Saudi Arabia with 1,109 thousand barrels per day.

Crude Oil Imports (Top 15 Countries)

(thousand barrels per day)

Country	Apr-13	Mar-13	YTD 2013	Apr-12	YTD 2012
CANADA	2,517	2,518	2,633	2,421	2,464
SAUDI ARABIA	1,107	1,284	1,098	1,587	1,447
MEXICO	905	608	845	953	976
VENEZUELA	811	742	755	835	835
IRAQ	455	426	456	395	362
COLOMBIA	440	447	393	430	425
NIGERIA	320	376	336	424	391
ECUADOR	310	213	235	201	177
KUWAIT	232	367	313	234	326
ANGOLA	154	85	156	233	244
RUSSIA	98	24	53	106	89
ALGERIA	65	34	40	104	132
CHAD	63	73	56	0	16
LIBYA	62	40	28	68	39

BRAZIL	60	85	72	215	288

Total Imports of Petroleum (Top 15 Countries)

(thousand barrels per day)

Country	Apr-13	Mar-13	YTD 2013	Apr-12	YTD 2012
CANADA	3,163	3,004	3,251	2,931	2,979
SAUDI ARABIA	1,109	1,284	1,102	1,589	1,451
MEXICO	973	677	922	1,002	1,050
VENEZUELA	847	763	781	904	892
RUSSIA	579	454	452	388	395
COLOMBIA	465	479	416	472	464
IRAQ	455	426	456	395	362
NIGERIA	405	403	388	483	429
ECUADOR	322	218	239	201	179
KUWAIT	238	367	315	235	327
ANGOLA	167	98	171	253	258
ALGERIA	160	74	113	259	278
UNITED KINGDOM	131	111	113	204	172
INDIA	98	40	52	66	39
BRAZIL	96	123	102	237	301

Note: The data in the tables above exclude oil imports into the U.S. territories.

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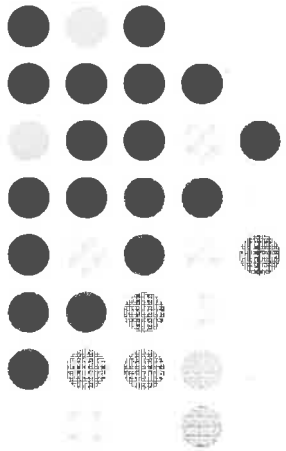
Evaluating Canadian Crudes in US Gulf Coast Refineries

Pat Swafford

Spiral Software

Crude Oil Quality Association Meeting

February 11, 2010



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Introduction

- Introduction to Spiral Software
- Overview of typical USGC operations
- Changing the USGC crude slate
- Comparison of Canadian crude grades with USGC typical crude mix
- Evaluating Canadian crudes from a quality perspective

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Introduction to Spiral

- Spiral provides tools and services that enable our clients to make the best choices in trading and refining crude oil
- Over 60 client companies spanning integrated oil companies, refiners, consultants and trading firms
- Global implementations by BP, Chevron and Shell
- Application examples:
  - **Enterprise crude oil knowledge management:** Intuitive tools with strong inter-element links, allowing users to share expertise and consistent data across business areas
  - **Feedstock screening and ranking:** Fast, transparent models for screening crudes and identifying optimal blends—minimizing processing risk and maximizing margin

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OVERVIEW OF USGC OPERATIONS

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Typical USGC Refinery Configuration

Process	Capacity (bpd)
Crude	178,000
Vacuum	82,000
Coker	28,000
FCC	59,000
Reformer	36,000
Hydrocracking	17,000
Alkylation	12,000
Isomerization	5,000
Sulfur	400 tpd

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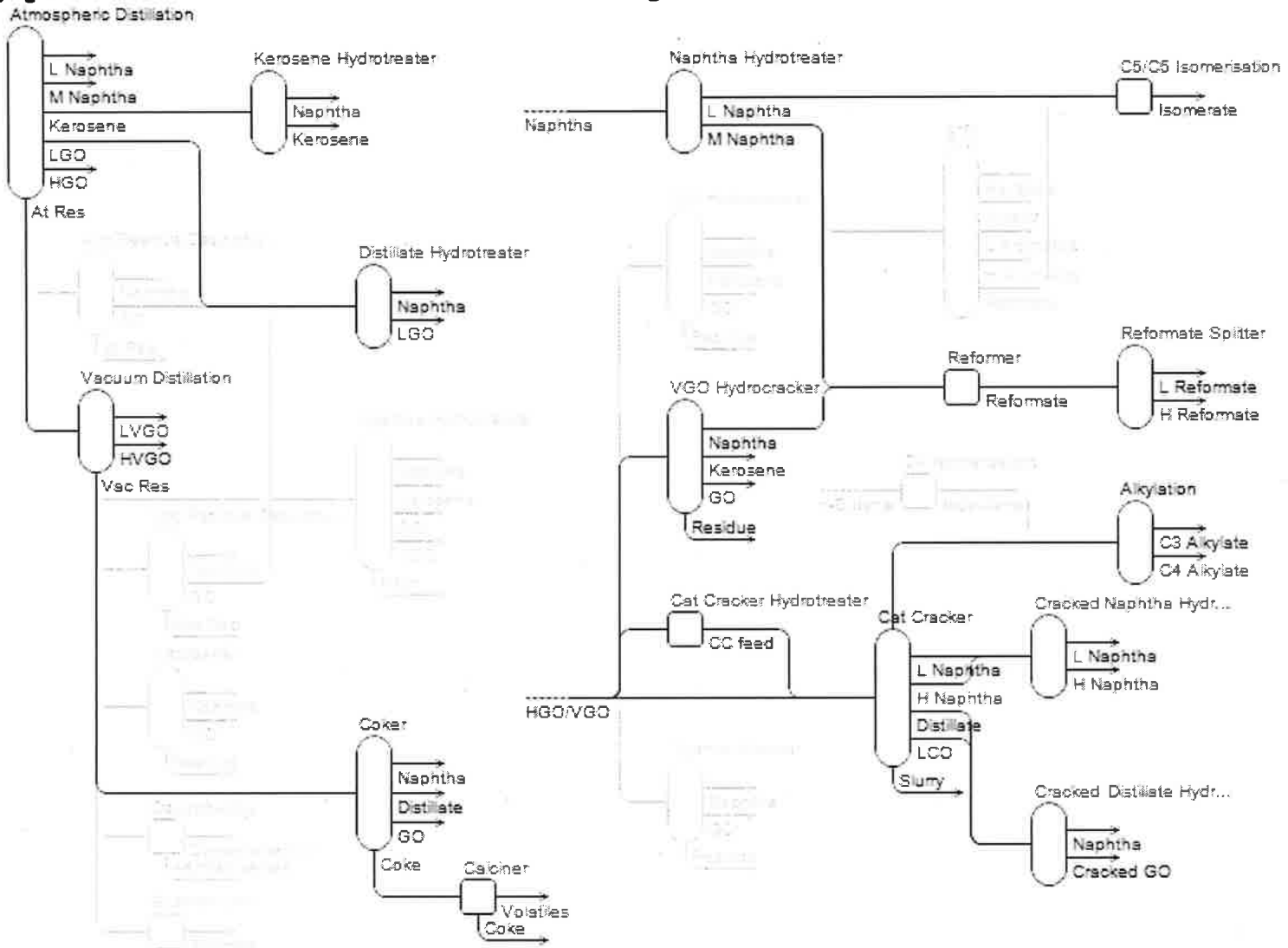
Typical USGC Refinery Flowsheet



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Typical* USGC Crude Mix

OPEC	55%
Non-OPEC	45%
API Gravity	29.5
Sulfur (wt %)	1.64

* December 2008 through November 2009 data from EIA website

Country of Origin	Percentage
US	14.0
Algeria	4.6
Angola	3.4
Iraq	3.9
Kuwait	2.6
Nigeria	8.4
Saudi Arabia	9.7
Venezuela	13.2
Brazil	2.3
Canada	1.8
Colombia	2.7
Mexico	17.1
Russia	5.2
United Kingdom	1.5
Other	9.4

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CHANGING THE USGC CRUDE SLATE

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USGC Crude Mix Will Change

The proposed Keystone Pipeline expansion will make 500,000 barrels per day of capacity available to move Canadian crude oil to the US Gulf Coast by 2012.

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Adding Canadian Crudes to the USGC Crude Slate

- Refinery configurations are unique and typically geared toward a certain type of crude slate
- Some of the more challenging grades of Canadian crudes cannot be processed in high percentages in a typical refinery
- Understanding the possible combinations of crudes and the acceptable amounts of each gives refinery planners and traders information that can be used to make economic decisions

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COMPARING CANADIAN AND USGC CRUDES

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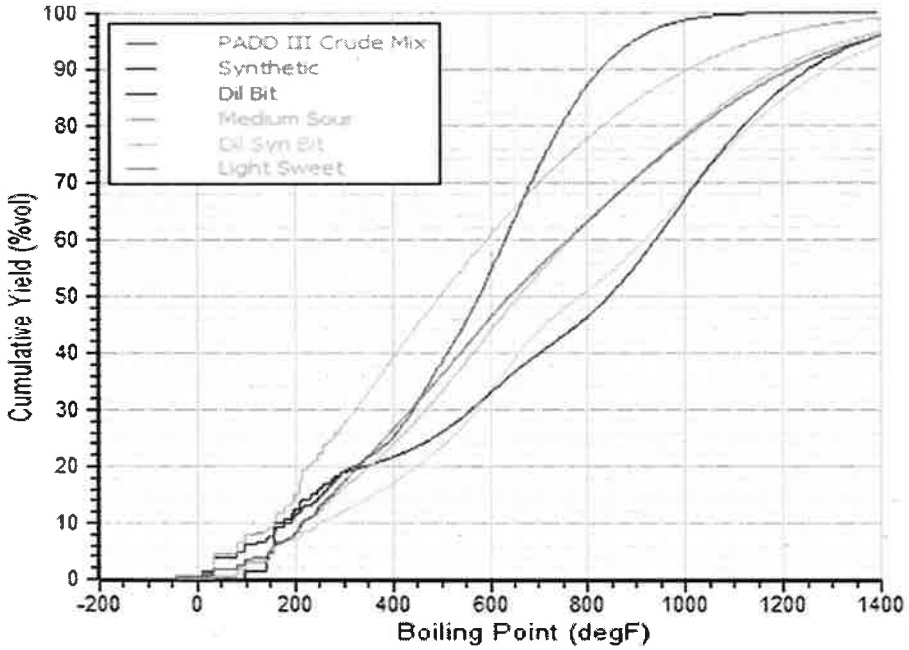
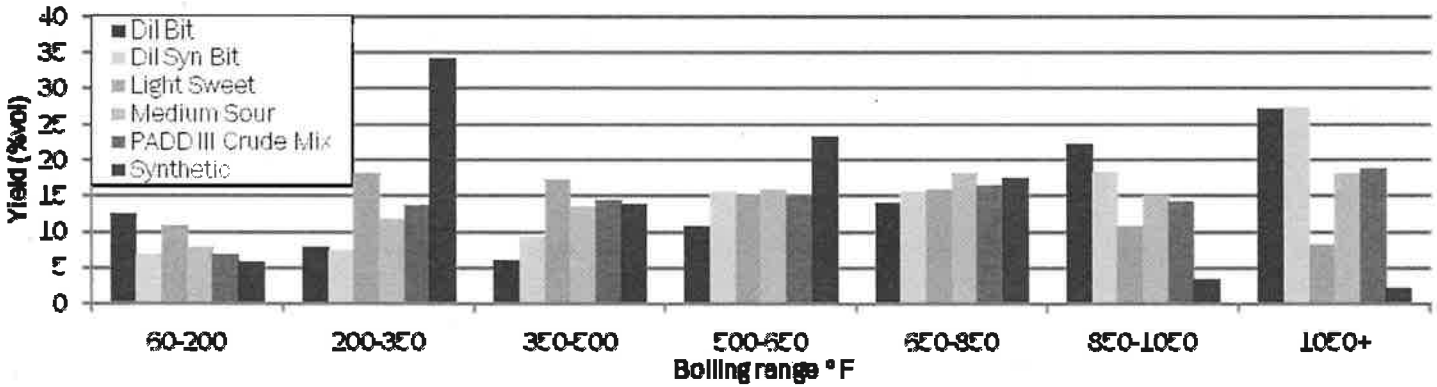
Comparison – USGC vs Canadian Grades





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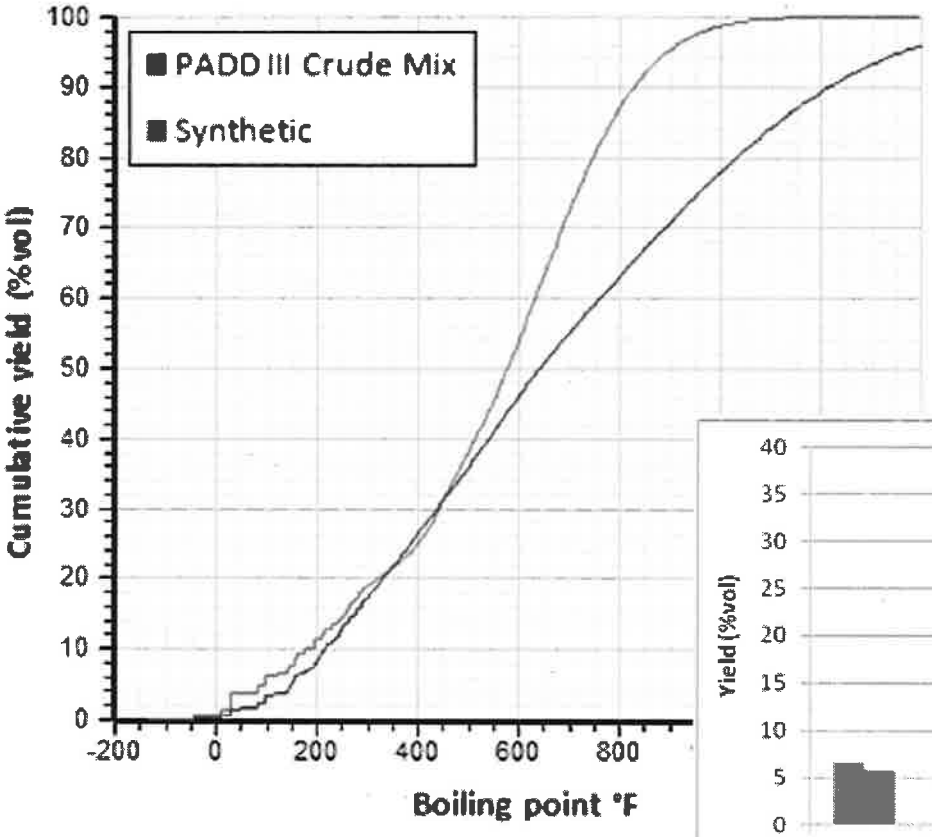
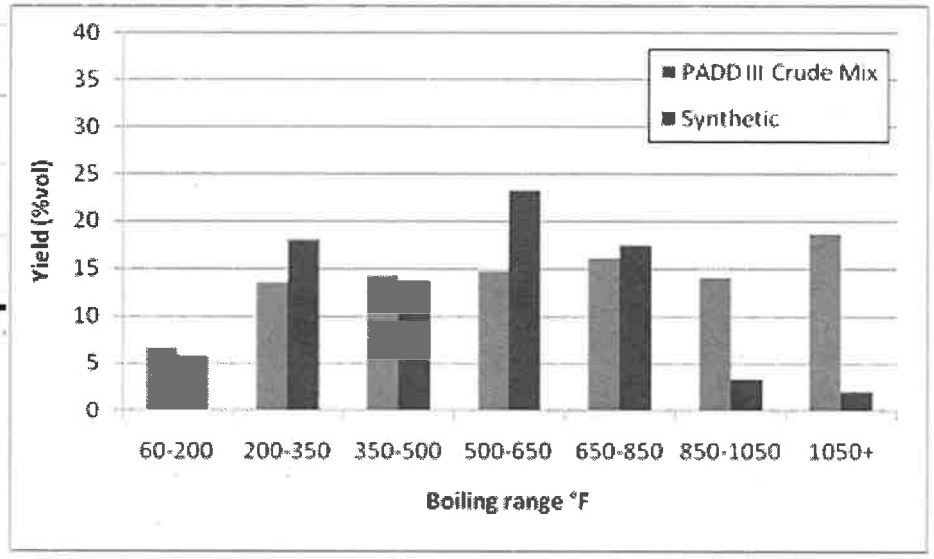
Synthetic Crude *vs* Typical USGC mix





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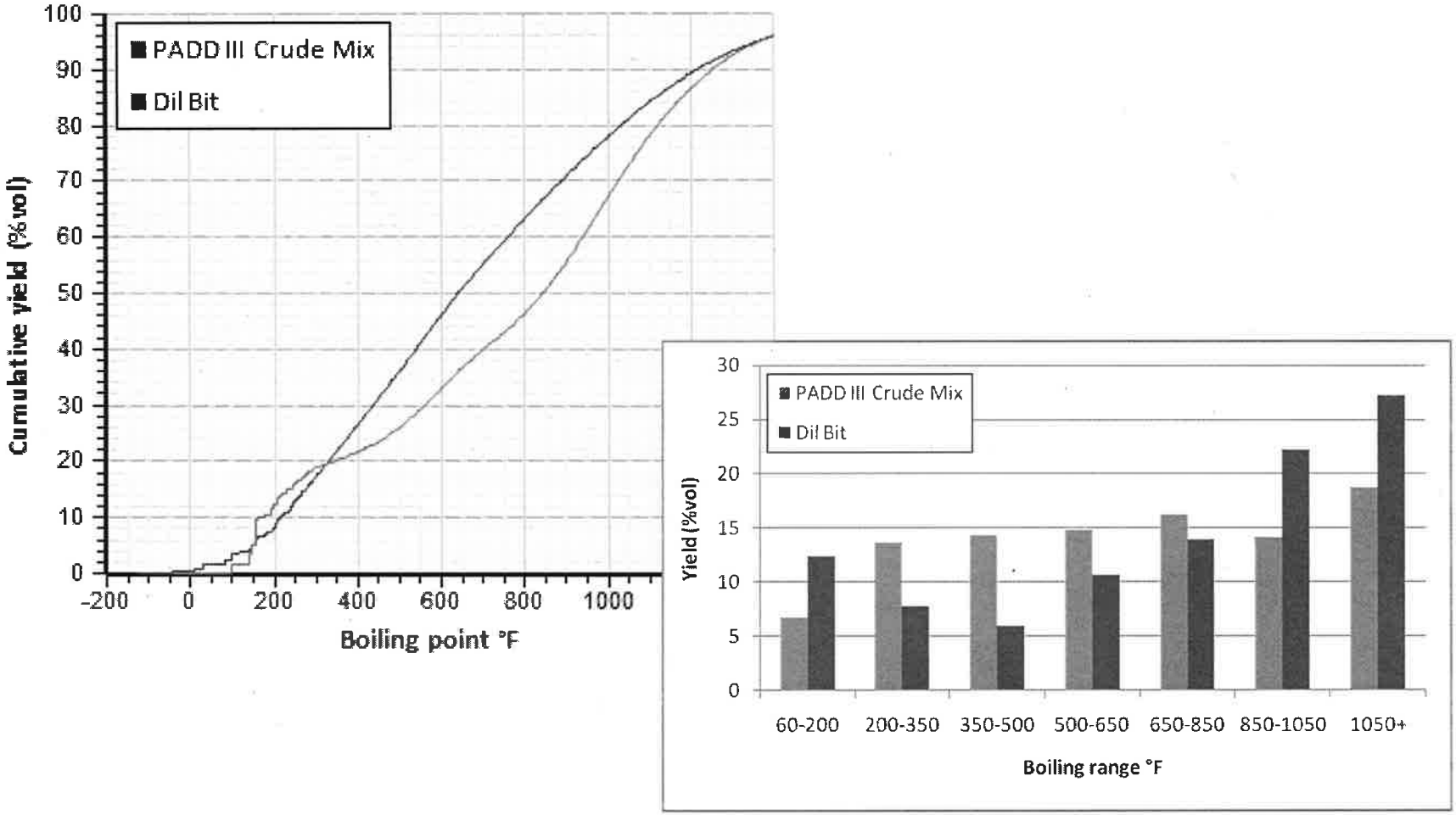
Dilbit crude *vs* Typical USGC mix



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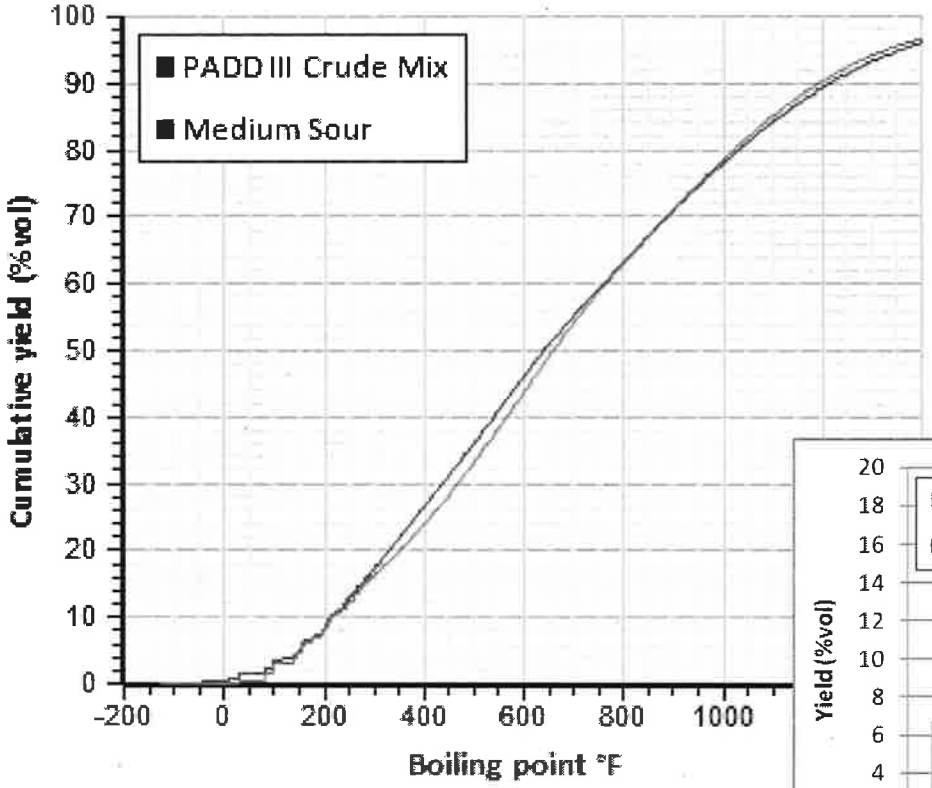
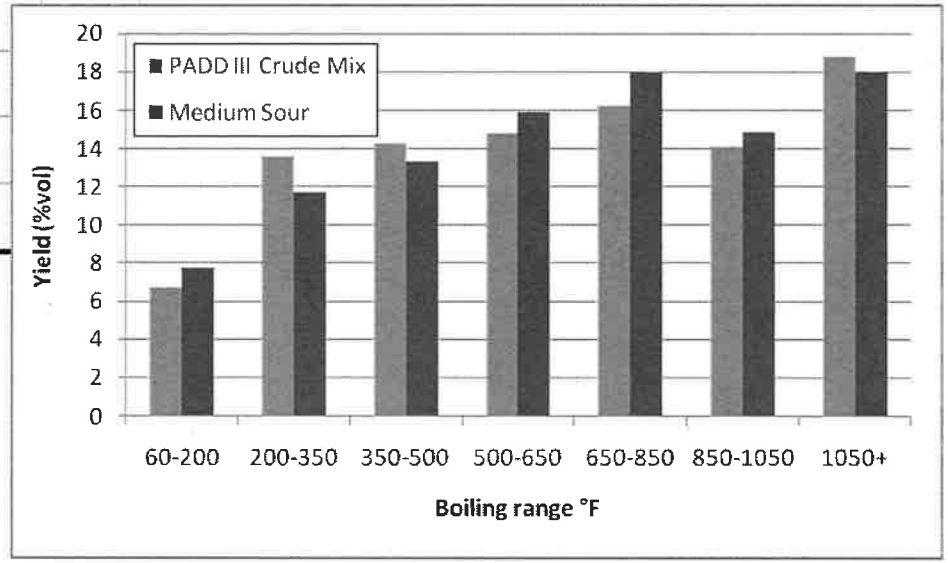
Medium sour *vs* Typical USGC mix





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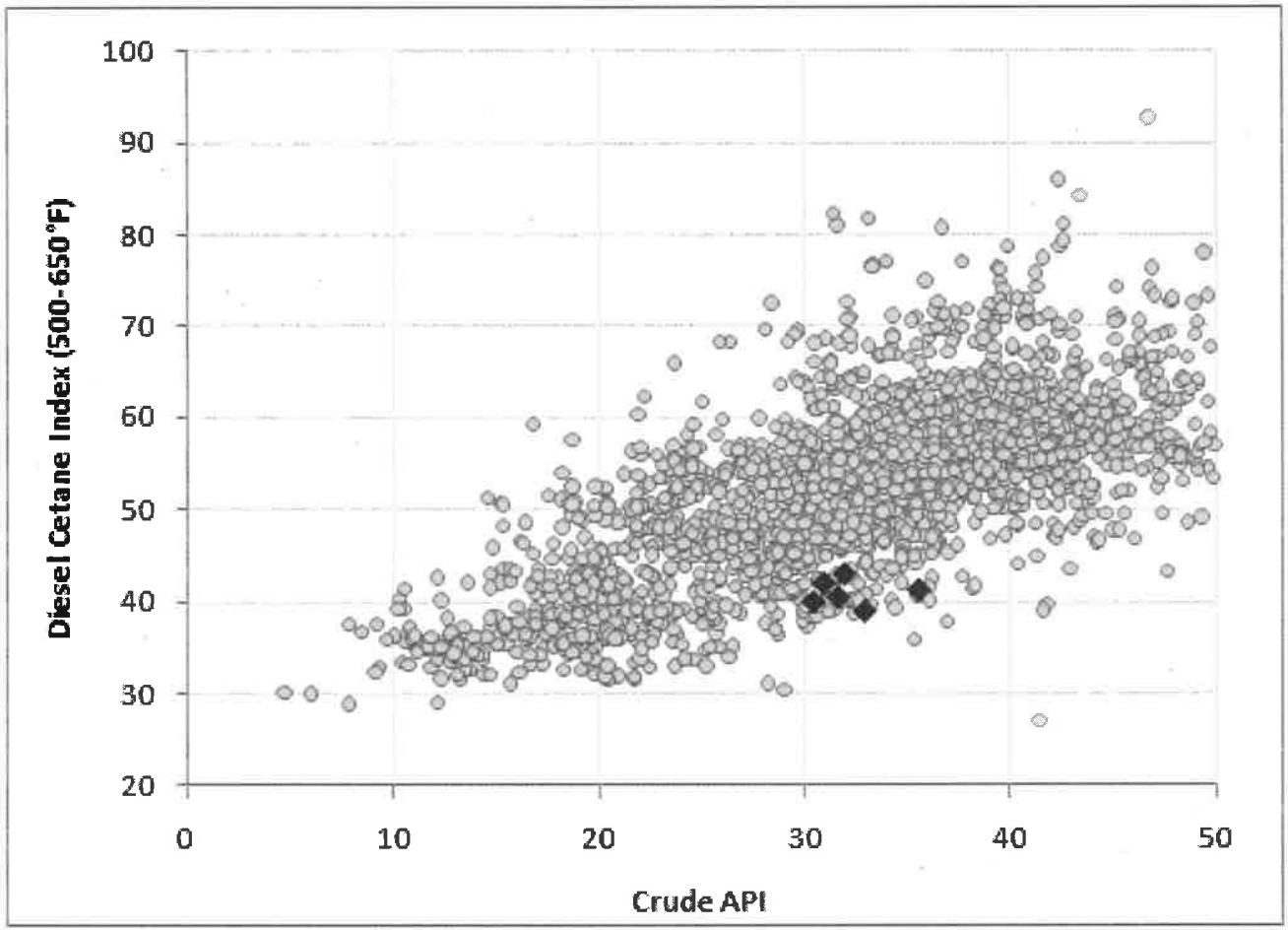
Synthetic Crude Diesel Cetane

Comparison to world crudes



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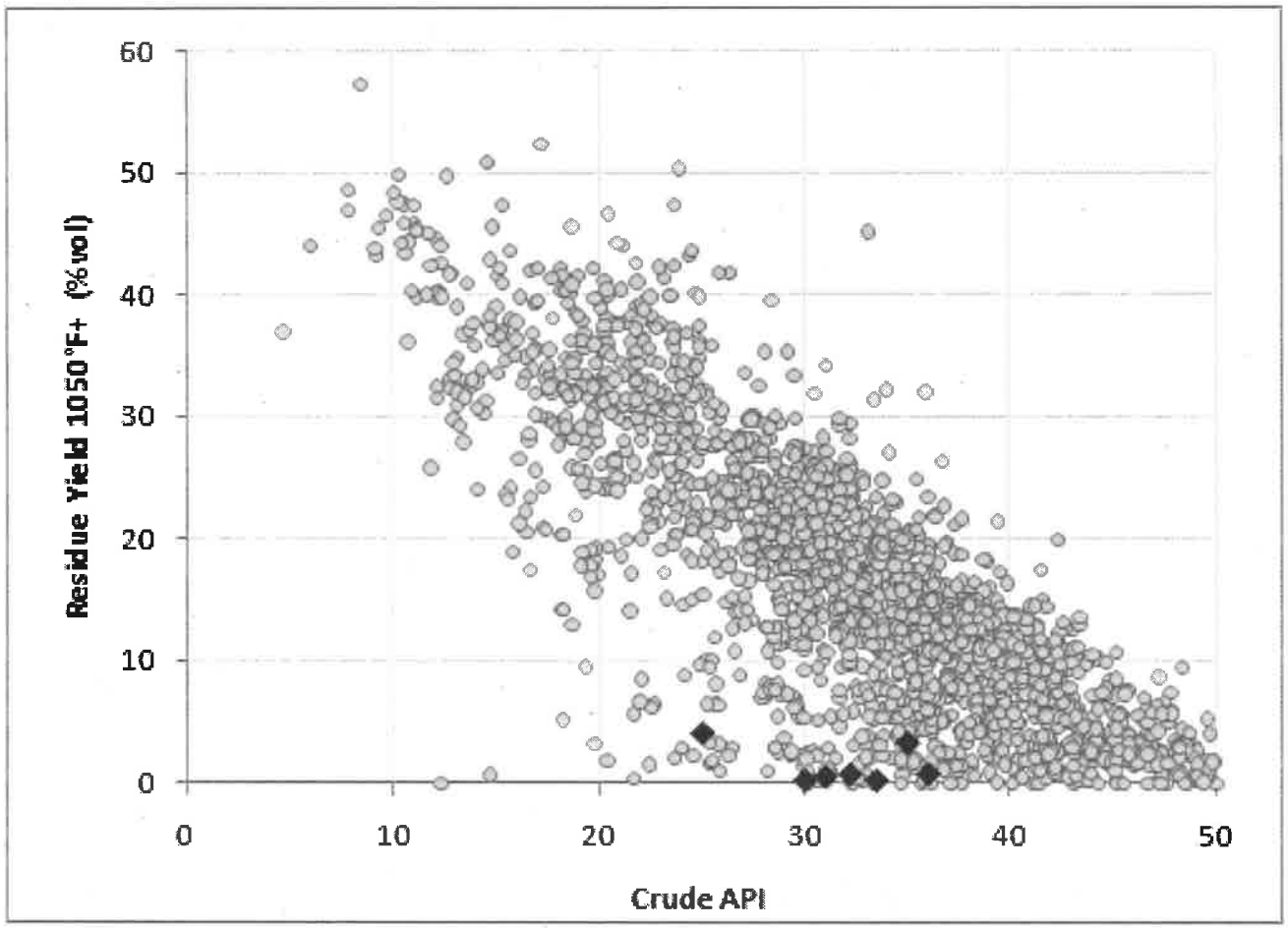
Synthetic Crude Residue Yield

Comparison to world crudes



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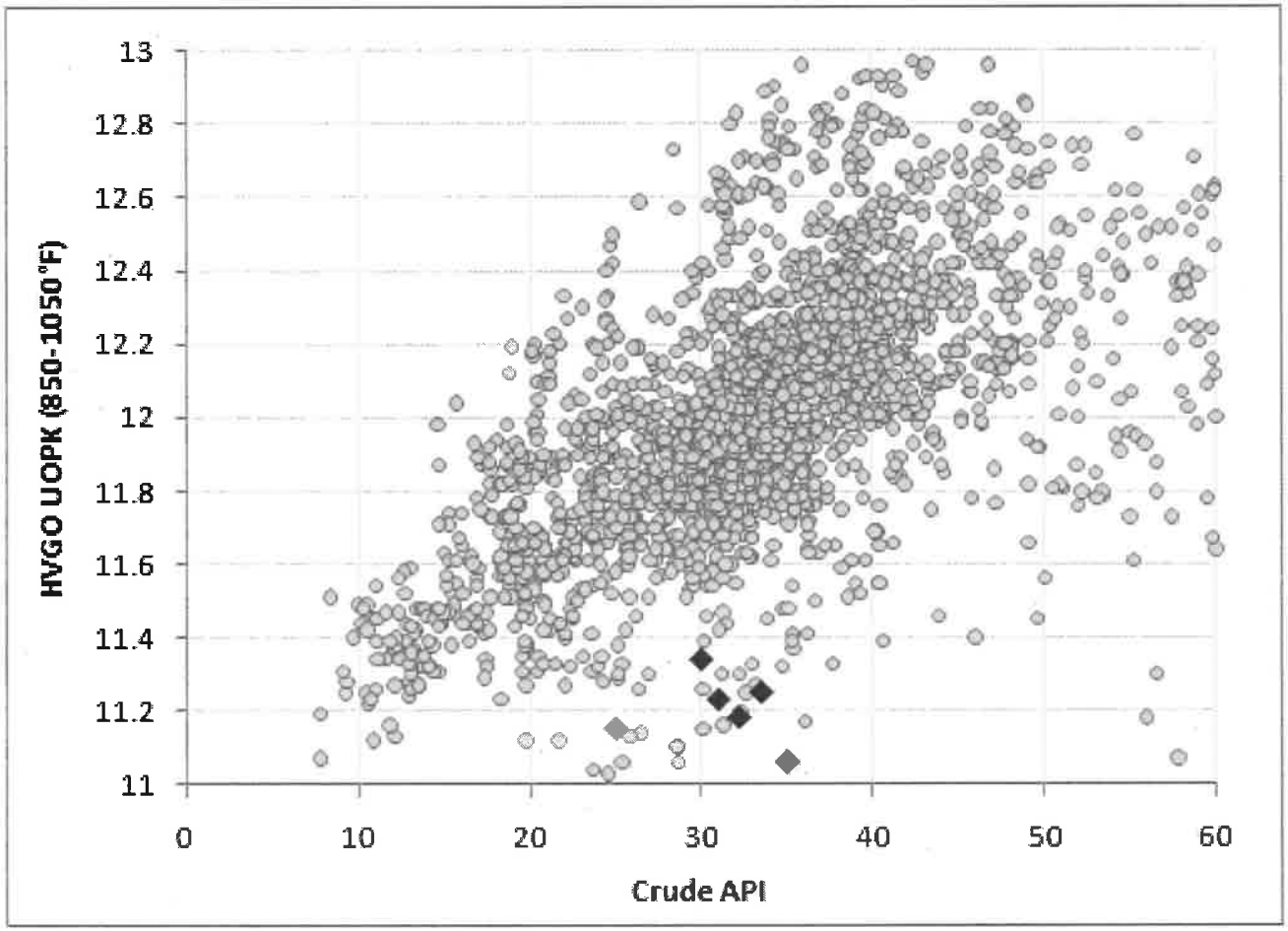
Synthetic crude HVGO UOPK

Comparison to world crudes



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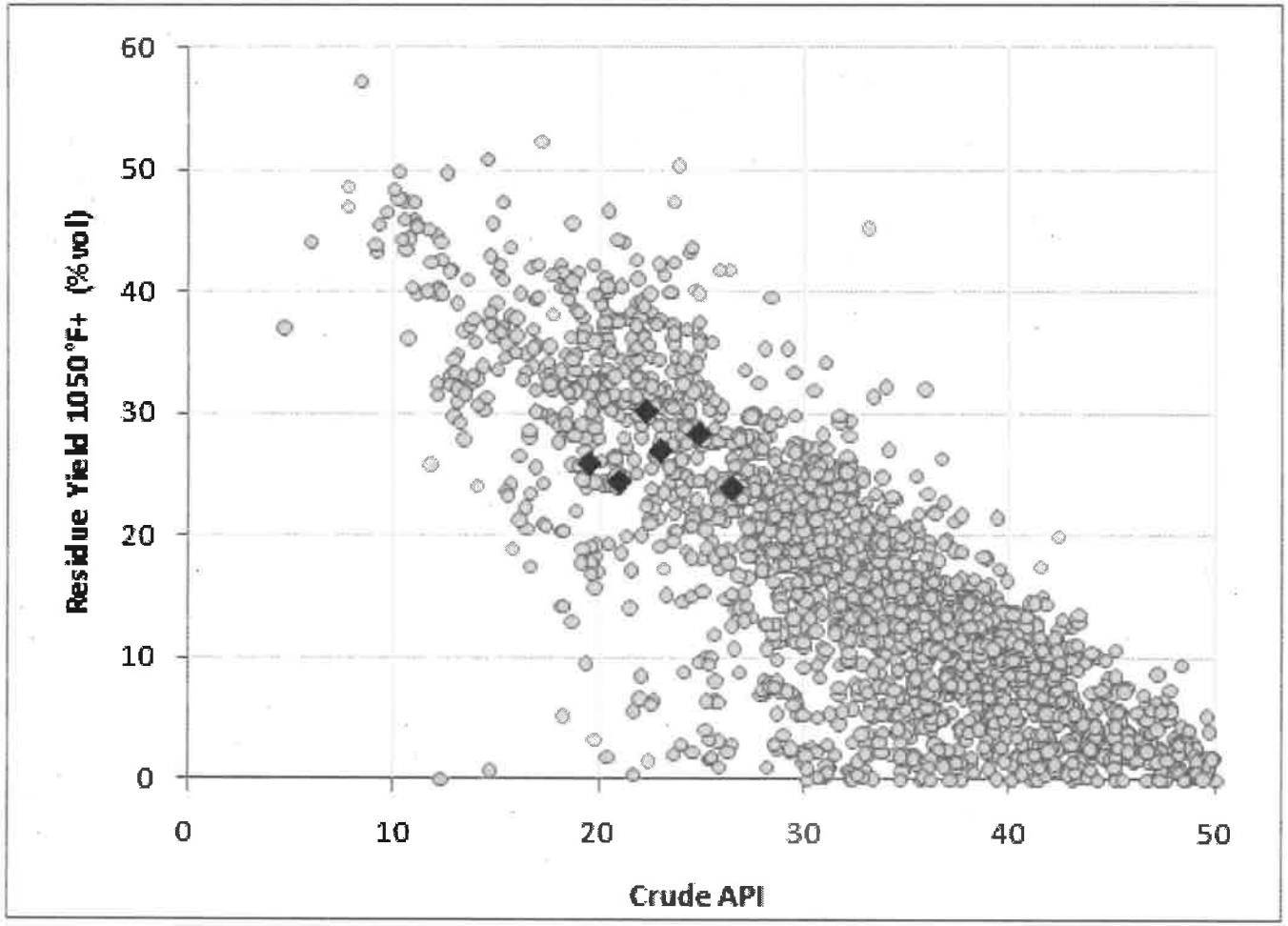
Heavy Sour Crude Residue Yield

Comparison to world crudes



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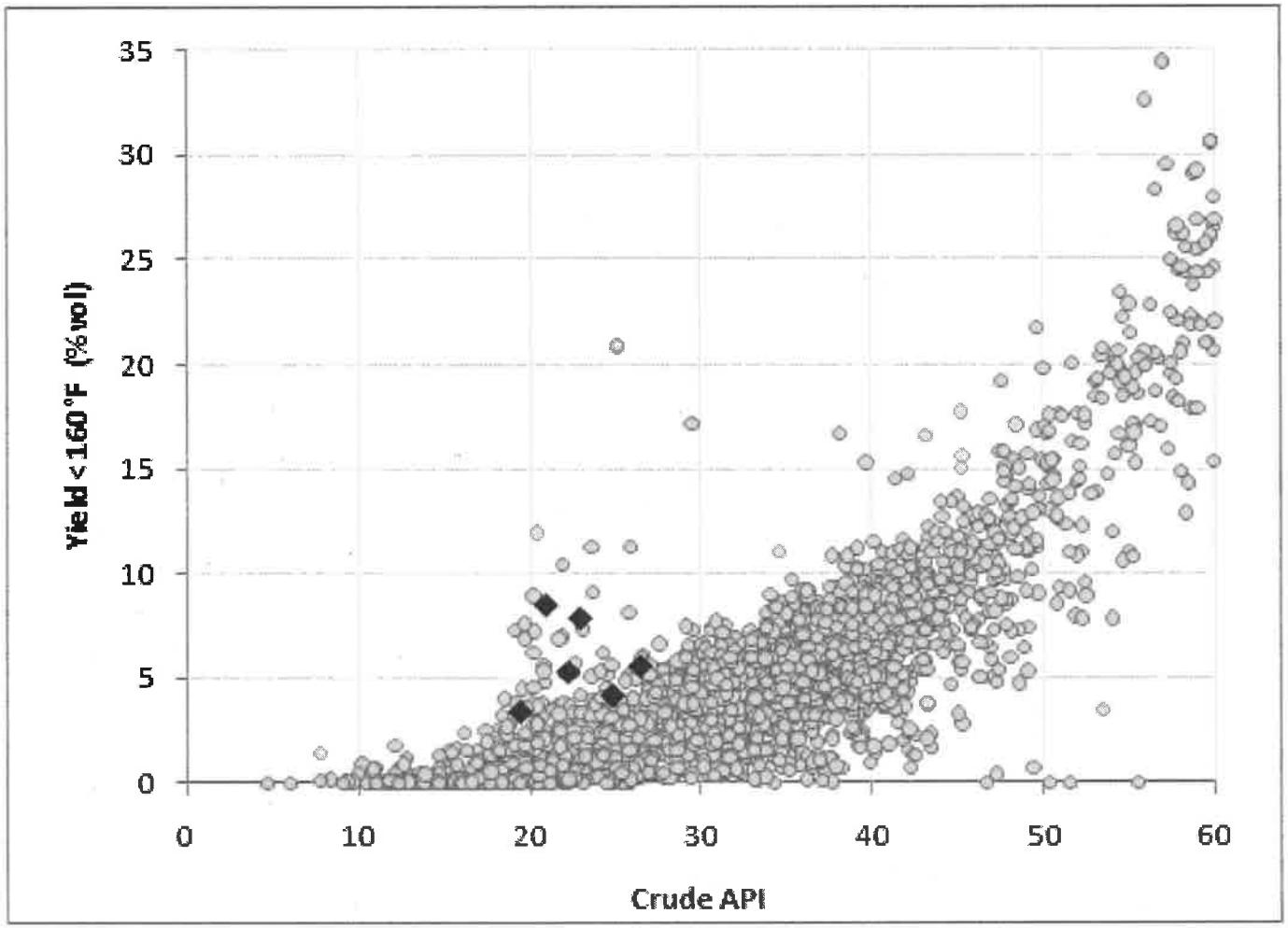
Heavy Sour Crude LSR Yield

Comparison to world crudes



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More than just LP evaluation

- Every refiner makes crude purchase decisions on the basis of refinery LP model economics (and rightly so)
- Anytime opportunity crudes or crudes outside the normal operating envelope are considered, a quality evaluation outside of the refinery LP model is warranted
- Refinery LP models typically don't consider all of the quality aspects of a crude oil
  - Acidity
  - Other properties
- Refinery LP models solutions identify a single-point of operation. The refiner should consider the entire feasible operating envelope of a crude oil before making the purchase decision.

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EVALUATING CANADIAN CRUDES ON A QUALITY BASIS

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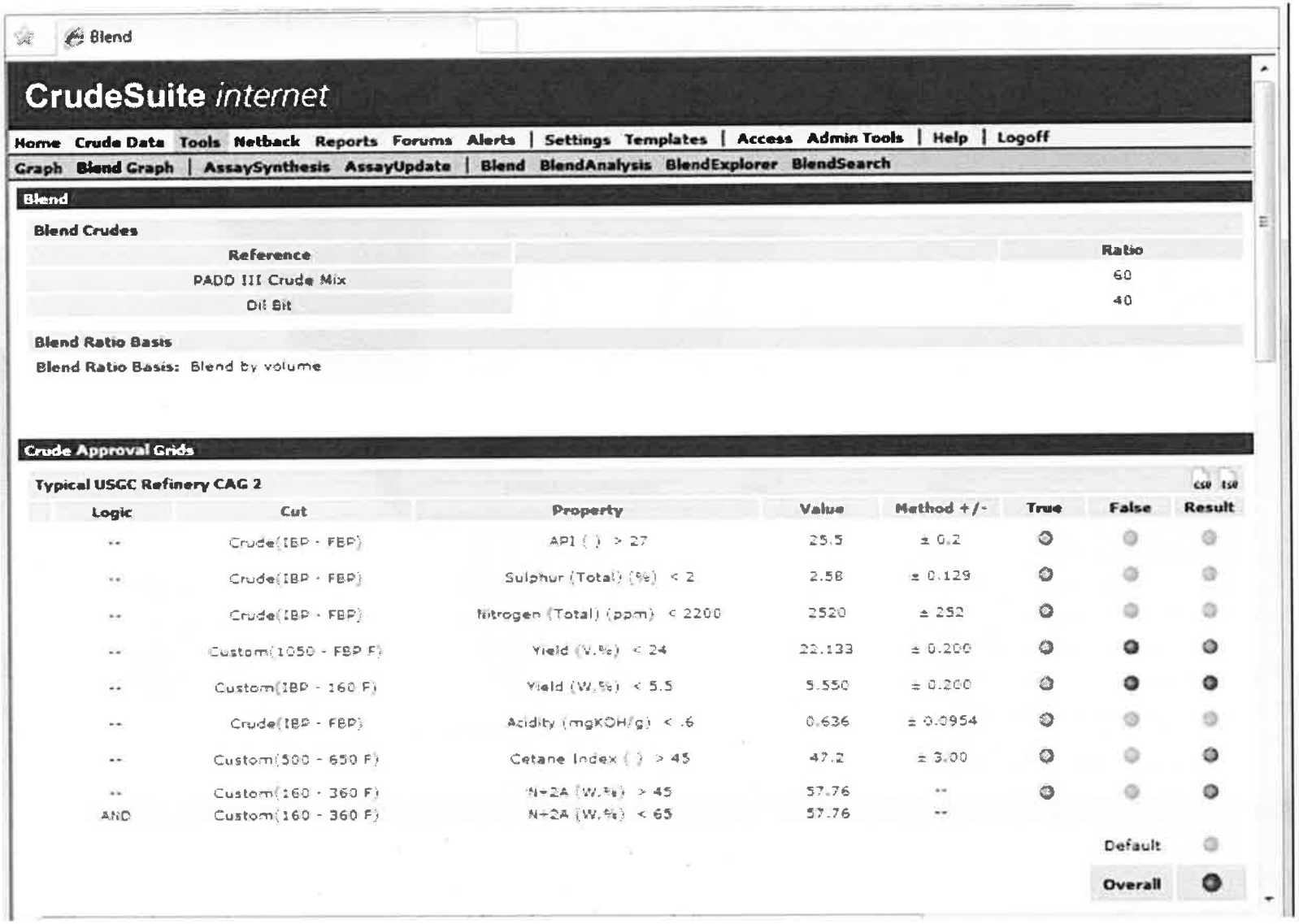

Analyzing the Limiting Criteria of Unacceptable Blends

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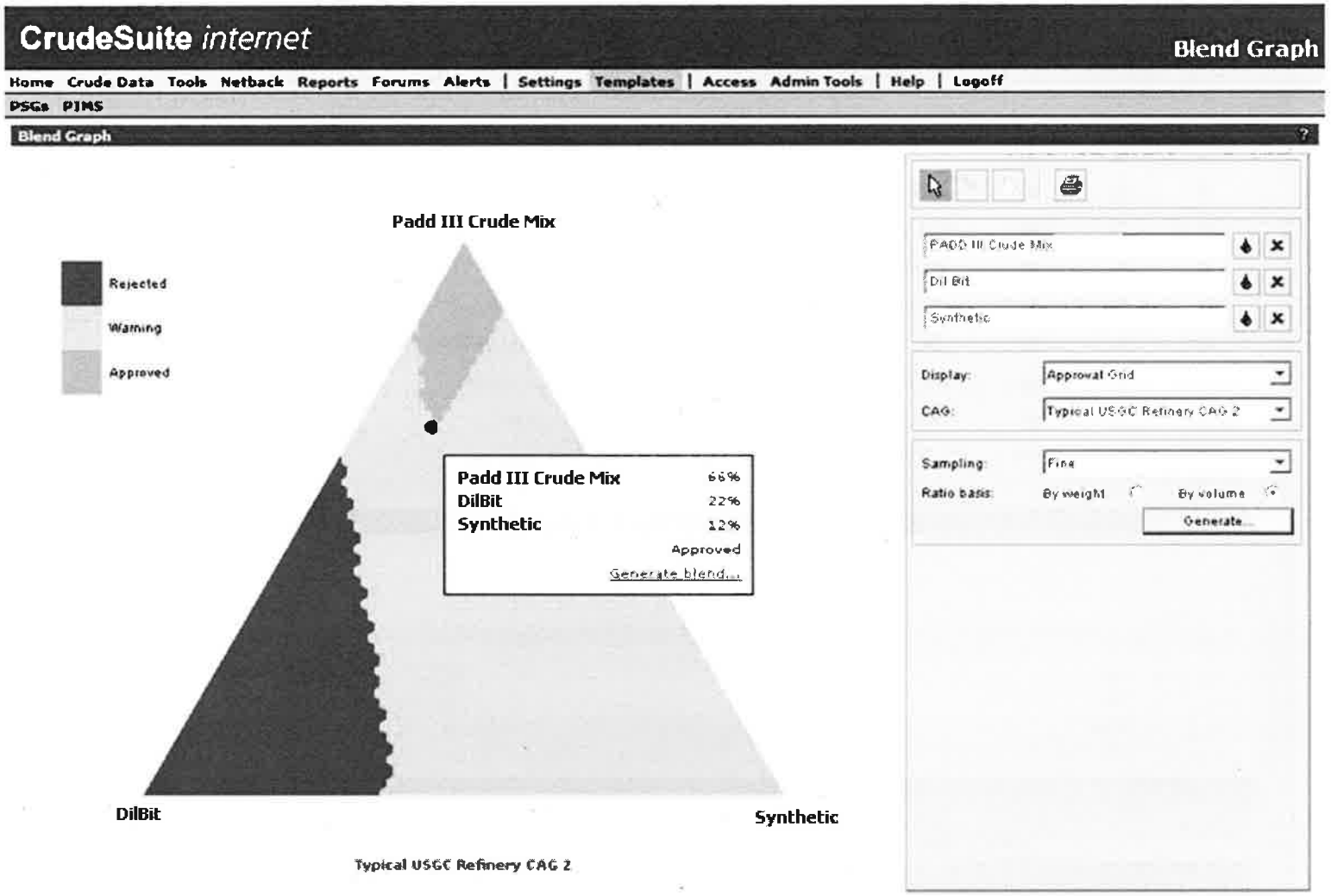

Analyzing the Range of Feasible Blending Options

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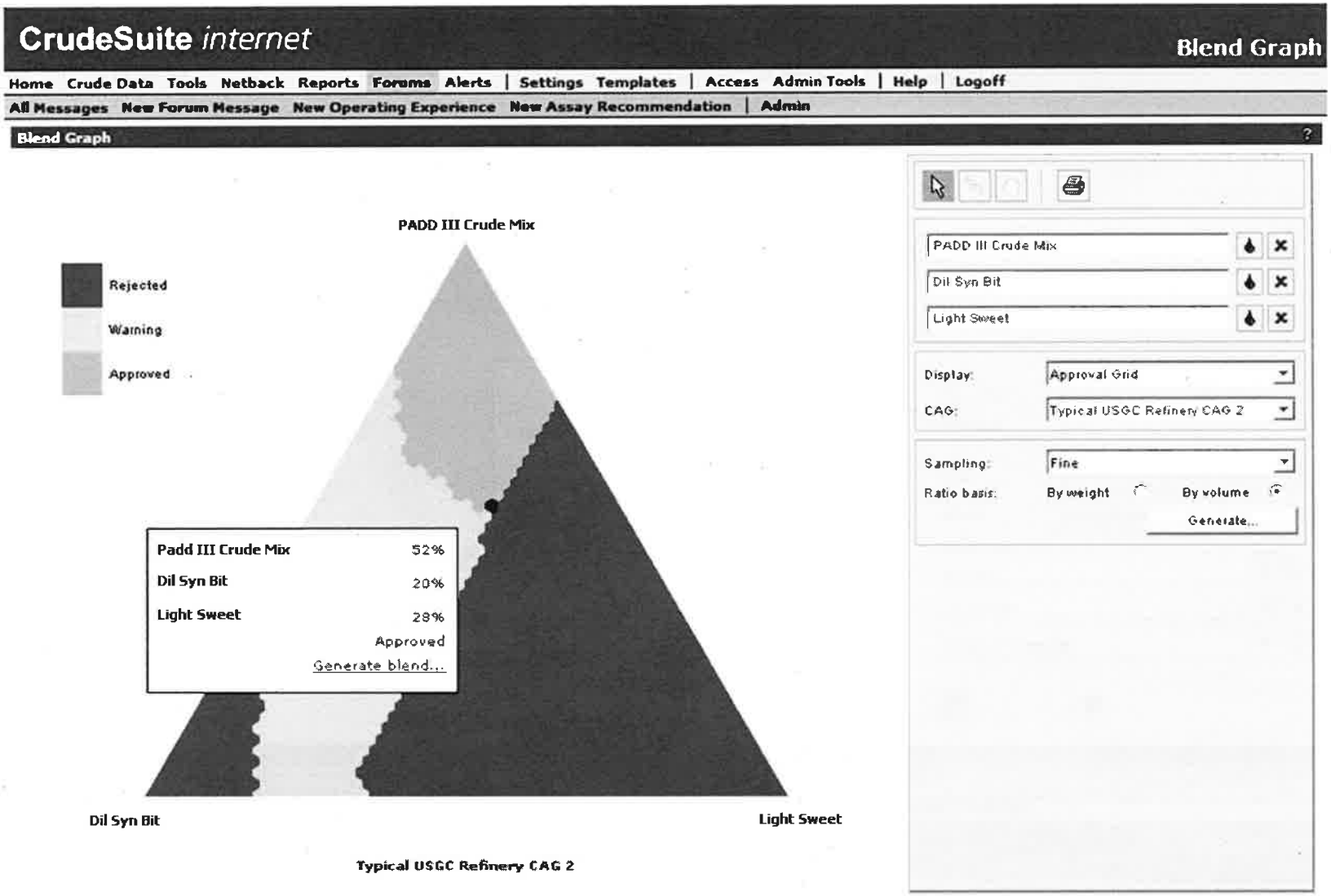

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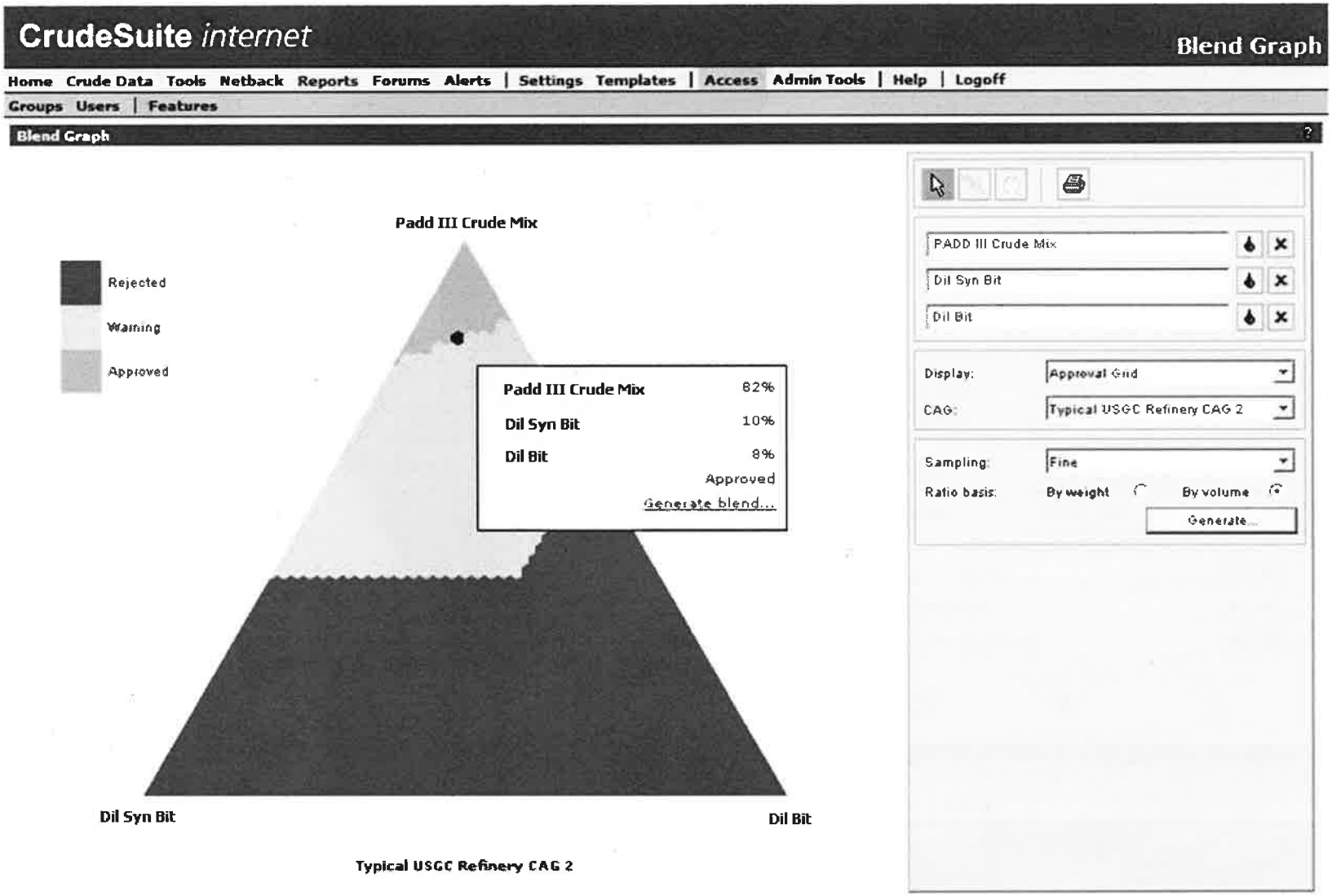

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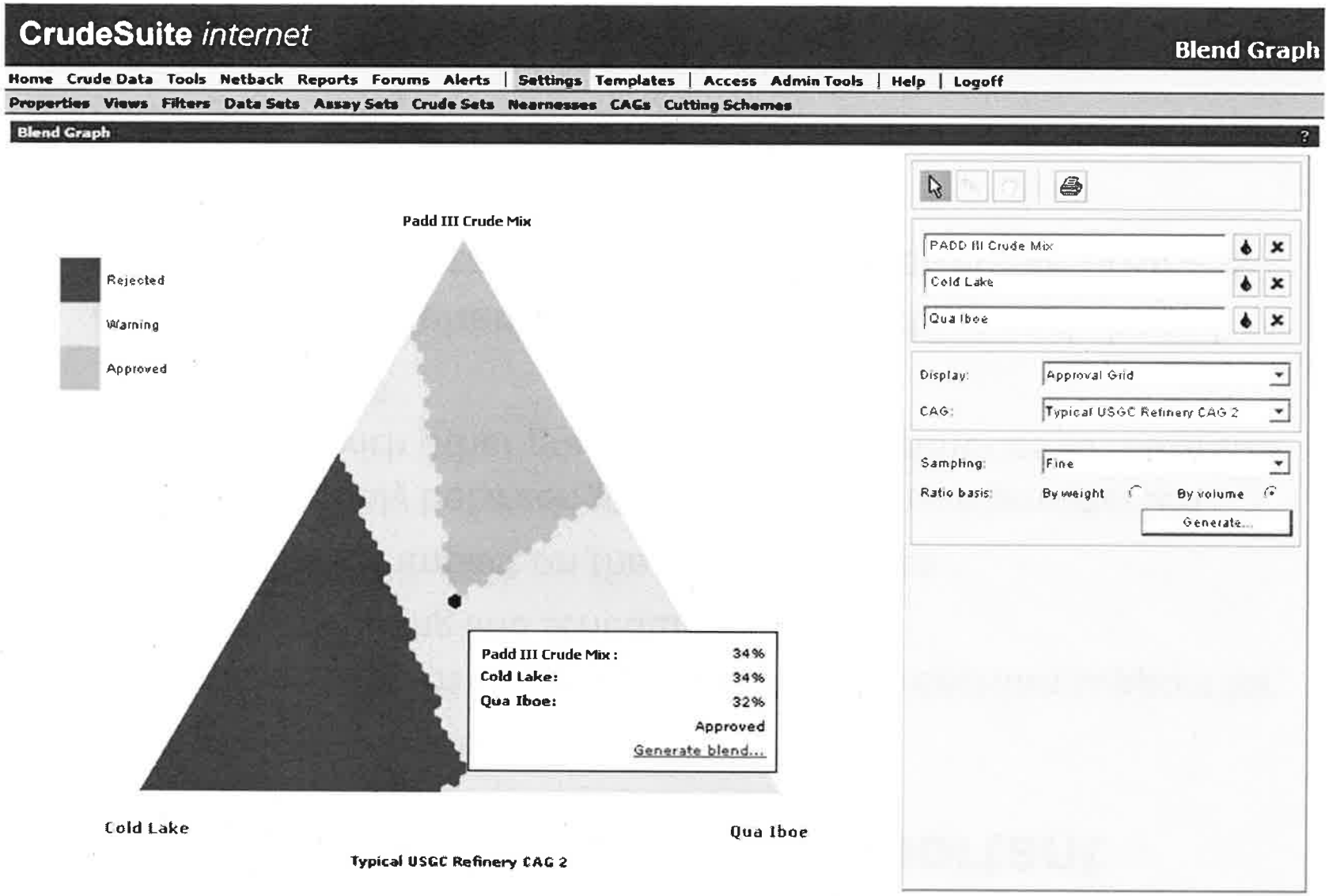

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Crude Quality Analysis is Important

- Crude oil properties
  - Form the basis of crude oil descriptions in decision support for trading, planning and scheduling
  - Have a major impact on the value of crudes
  - Differ not only between grades, but may have unexpected synergies with other grades that enable refineries to maximize their margins
- Accurate, comprehensive, current, consistent and shared crude property data is a prerequisite for effective business processes

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Conclusions

Successfully processing Canadian crudes requires a good understanding of:

- How the quality of Canadian grades compares to the typical USGC crude mix
- How the qualities interact with the base crude mix

Spiral's crude oil knowledge management tools enable this by:

- Analyzing assays of individual grades of crude and blends of crudes from a quality perspective
- Identifying the feasible operating region for crudes that reflect actual refinery operating constraints

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Refinery Operations
Engineering Solutions, Maintenance, Reliability, Automation and Equipment

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Zero/Low Rare Earth FCC Catalyst Technology Ready for Commercialization

New Formulations are Equally Effective on Hydrotreated Feedstocks and Resid Feedstocks

Shawn A. Abrams, Vice President and General Manager, Grace Davison Refining Technologies

Grace Davison announced earlier this summer the successful global commercialization of eight fluid catalytic cracking (FCC) catalysts and additives with zero or low rare earth (RE) content.

Shawn A. Abrams, Vice President and General Manager for Grace Davison Refining Technologies, said, "In order to relieve the cost pressure on customers while maintaining or improving product performance, Grace Davison Refining Technologies has responded quickly to the issues of rare earth price and availability by developing eight new zero/low rare earth catalysts and additives. Grace is investing capital at its manufacturing facilities to make these technologies available globally."

The REpLaCeR™ family includes five new catalysts for both hydrotreated and resid feed processing with zero and low RE content: REsolution™, REBEL™, REACTOR™, REMEDY™ and REduceR™ FCC catalysts. The REpLaCeR™ family of catalysts utilizes proprietary zeolites and state-of-the-art stabilization methods to deliver performance similar to current RE-based FCC technologies. For example, extensive R&D work to develop the REBEL RE-free high matrix catalyst system for FCC applications delivers the same activity and selectivity over resid feedstock as the well proven MIDAS®-100 catalyst (**Table 1**).

In addition, Grace has recently introduced ResidUltra™, a new catalyst with 40% less RE than benchmark resid catalysts. Finally, a series of low RE environmental additives is currently in commercial trials. These include Super DeSOX-OCI™

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Table 1. REBEL™ catalyst delivers the same activity and selectivity over resid feedstock as RE metal based catalysts.

ACE Yields at Constant Conversion (CPS-3 deactivation, 3000 ppm Ni + V)		
	REBEL™ Catalyst	**MIDAS®-100**
Cat-to-oil	5.8	5.5
Dry Gas, wt%	1.8	1.8
Propylene, wt%	3.5	3.5
Butylenes, wt%	5.2	5.4
Gasoline, wt%	46.6	46.8
Bottoms, wt%	9.6	9.5
Coke, wt%	4.2	4.3

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CALENDAR

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and Super DeSOX-MCD™ sulfur transfer additives.

RE metals have always played an important role in FCC operations for stabilization of the Y zeolite component of FCC catalysts. However, recent export quota restrictions on RE metals from China has caused the prices of these RE-based catalysts to rapidly rise. China is the primary source of RE metals, which is why more cost effective RE-free catalyst have been highly sought after by many refiners. A more detailed discussion on the development of RE-free FCC catalysts is discussed in Vol. II, No. 3 of *Refinery Operations*: "The Development of Rare-Earth Free FCC Catalysts," by Colin Baillie and Rosann K. Schiller.[1] ■

1. Vol. II, No. 3 of *Refinery Operations* can be downloaded from the *Refinery Operations* website (www.refineryoperations.com) or contact Rosann Schiller at Grace (rosann.schiller@grace.com).

GRACE Davison
ART Advanced Refining Technologies

PROCESS OPERATIONS

Increasing Desalting Capacity

Refiners are increasing desalting capacity as two-stage desalting capacity is increasing with heavier crudes and blended feedstocks. For example, a refinery processing 100,000 bpd of crude receives roughly over 5.0 tons per day of salts and solids.

Management of this material in the refinery is critical due to its impact on corrosion of distillation columns, fouling of process equipment, as well as reduction of catalyst life. In addition to increased salt content removal capacity, the latest injector/mixer desalter technology provides more efficient utilization of wash water and chemicals, and improved crude-water separability.

It is generally understood that dehydration efficiency of a desalter is usually 95% in a single stage and up to 99% in a two-stage configuration. In addition, if the salt compounds (typically NaCl, $CaCl_2$ and $MgCl_2$) that are not removed from the oil, higher levels of HCl-related corrosion can be expected in downstream process operations when considering that higher severity conditions and temperatures are expected when upgrading low gravity crudes.

Desalting technology continues to improve in reliability and reduced energy consumption as the impact of organic acids and asphaltenes on downstream refinery operations needs to be minimized as will be discussed in further detail in the next issue of *Refinery Operations*. ■

Upgrading FCC LCO to Diesel Pool

Many refiners are still feeling the impact of ULSD regulations on the addition of FCC light cycle oil (LCO) to the diesel pool. LCO, with a cetane number averaging around 25, is much higher in sulfur level than straight-run (SR) diesel and contains up to four times the concentration of aromatics, making LCO significantly denser.

Addition of FCC LCO into the ULSD pool has required modification of distillate hydrotreating units for much higher severity operation. In addition, FCC feed hydrotreating or mild hydrocracking has been required with high sulfur feeds in order to shift a significant portion of FCC LCO into the USLD pool. Up to 50% of the FCC gasoline sulfur can be concentrated in the back end (> 425 °F) of the gasoline pool. Available methods for analyzing total gasoline sulfur include:

- ASTM D2622: A wavelength dispersive X-ray fluorescence technique capable of detecting sulfur levels greater than 10 ppm
- ASTM D5433: An oxidative combustion based technique using a UV fluorescence detector. This test is applicable in the wide range of 1 to 8000 ppm
- ASTM D4045: An oxidative combustion based technique using hydrogenolysis and rateometric colorimetry. Sulfur detection is in the range of 0.02 to 10 ppm.

■

Assessing Corrosivity of High TAN Crudes

Concerns over processing crudes with TAN numbers greater than 1.0 have lead to discussions of oil sands dil/synbit segregation from other heavy crude oils. However, this could potentially cause significant logistical midstream problems with pipeline and terminal systems charged with transporting segregated crudes to the refinery

The Canadian Crude Quality Association (CCQTA) and producers in the oil sands play have been addressing this issue with a variety of ongoing projects. From a practical

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perspective, knowledge of a crude feedstock's potential corrosivity through currently available test methods has often been lengthy and expensive, and has led to inaccurate results.

To more accurately and quickly determine the corrosivity potential of opportunity crudes, Southwest Research Institute (SwRI) has developed radio tracer technology (RATT) to measure crude oil corrosivity.

According to information available from SwRI, test coupons are irradiated to develop suitable tracers for detection using on-line gamma ray spectroscopy. Corrosion is then measured by monitoring the buildup of radioactivity in a closed loop system as a function of time. Detection and measurement of corrosion is available in real time for heavy crudes and high TAN crudes at shorter test times of about four hours. The corrosion potential of these opportunity crudes can be indexed to the corrosion of known crudes through back-to-back testing or database reference, according to information available from SwRI (www.swri.org). ■

Ebullated Bed Hydroprocessing's Role in Bitumen Upgrading

The technical advantages for ebullated bed hydroprocessing in upgrading bitumen feedstocks versus thermal conversion processes, such as coking, include a less aromatic product. With the addition of hydrogen, there is a significant amount of sulfur and nitrogen reduction, along with the previously mentioned saturation of aromatic rings. Nevertheless, coking is the primary upgrading process of choice for the two largest bitumen upgraders (Suncor and Syncrude: about 1.0 million bpd of upgrading capacity). Other significant bitumen upgraders include Husky Oil and Shell.

Husky Oil processes over 55,000 bpd using ebullated bed hydroprocessing, followed by coking of the unconverted residue, whereas the Shell-led Scotford upgrader uses ebullated bed hydroprocessing alone for primary upgrading. All upgrading facilities require hydrotreating or hydrocracking to remove sulfur and nitrogen to levels normally handled in downstream refining facilities, such as with the refiners in the Midwest region of the US.

To be sure, upgrading facilities require significant sources of hydrogen, albeit through steam reforming plants or pipeline. As bitumen processing approaches more than 3.0 million bpd by 2015, what happens at the upgrading stage cannot ignore the downstream refineries, and their processes.

A key issue for bitumen and other SCO feedstocks are the challenges to improving distillate and gas oil quality. These problems are to some degree exacerbated by coking, where cracking in the absence of hydrogen promotes the formation of unusually high aromatic hydrocarbon species.

According to some experts familiar with processing bitumen feedstocks, this is not easily corrected in the conventional refinery processes, particularly when meeting ULSD specifications. This factor alone can limit the percentage of SCO in the typical refinery diet, which is why hydrocracking is expected to play a greater role in keeping SCO market values competitive with light crudes. In addition to producing high quality distillates and zero residue, hydrocrackers are inherently better able to handle the aromatics.

Recent interest in partial or field upgrading (for viscosity reduction and diluent savings) will also play an important role in upgrading bitumens. Many of these processes, such as deasphalting and visbreaking may play a larger role, especially where residue use for hydrogen and energy positively influences primary upgrading process selection. ■

INDUSTRY NEWS

New Refinery in Central Vietnam

Vietnam National Petroleum also known as Petrolimex has unveiled plans to invest $4.4-$4.8 billion for constructing the Nam Van Phong complex, a new refinery in central Vietnam. The complex with a capacity of 200,000 bpd will be built in Nam Van Phong facility in Khanh Hoa province.

The main products produced from the refinery will include petrol, diesel, jet fuel, kerosene, LPG and other petrochemical products. Petrolimex issued an initial public offering in late July, seeking investors for construction of the complex.

The company is plannning to join hands with PetroChina to construct a 225 km pipeline connecting Chinese state oil giant's Qinzhou refinery in Guangxi province with Petrolimex's K130 terminal in Vietnam's Quang Ninh province. The primary objective is to construct the pipeline by 2014 with an initial annual capacity of 10 million tonnes to take Chinese refined products to Vietnam. ■

New Pemex Refinery in Final Engineering Stage

Mexico's state oil company Pemex announced that is in the final engineering stage for its planned $10 billion (estimated) 250,000 bpd Tula refinery in Hidalgo state, company COO Carlos Murrieta told a webcast on August 2.

Mexico's energy minister Georgina Kessel said in June that the tender process for refinery construction will not be completed until the first half of 2012. Pemex officials had previously announced that the process would be completed in early 2011.

"The refinery will be working in coordination with the existing Tula refinery, and in that sense it's critical that we finalize the overall optimization. We have all the resources for that," Murrieta said. The new Tula refinery project, which was announced in mid-April last year, was initially scheduled to be completed in 2015. Neither Pemex nor the government has yet discussed pushing back the startup date. ■

Petrobras Investing in Mexican Refining Infrastructure

Petroleo Brasileiro (Petrobras) has unveiled plans to invest $11billion in various oil exploration, production and refining projects in Mexico between 2011-2015. The company plans to make a majority of the investment in the petrochemical plants and refineries in Mexico's Gulf states.

Petrobras plans to buy the Etileno XXI project in Coatzacoalcos, a port in southern Veracruz and construct an ethylene processing plan for the project with capacity to produce 1 million tons of ethylene and its derivatives. The production from this plant will meet the deficit for ethylene products in Mexico. ■

Valero Completes Purchase of Chevron Pembroke Refinery

US-based Valero Energy has completed the purchase of Chevron's refinery in Pembroke, Wales, along with its marketing and logistics assets throughout the UK and Ireland. Valero has purchased the refinery for $730million, excluding working capital, and was funded from available cash.

The company said the Welsh unit is the largest and most complex refineries in Europe and has total capacity of 270,000 bpd. Valero now has 15 refineries, with a combined capacity of 2.9 million bpd of throughput. ■

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Earthquake Damaged Sendai Refinery Restart Planned for Late 2012

Japan-based JX Nippon Oil & Energy plans to resume operations at its refinery in Sendai at the end of 2012. The refinery with a capacity to produce 145,000 bpd was shut down due to the damages caused by the massive earthquake that hit Japan in March.

The refinery's shipping facilities also caught fire, causing extensive damage. The company is also planning to construct a 1MW solar facility on the site of the refinery to meet the energy needs of the plant.

JX will invest $640 million for the reconstruction of the plant including the 1MW solar plant, reports Reuters. The refinery is the last one to be restarted after the March earthquake, while the other two damaged refineries in Kashima, Negishi are back online. ■

Inland US Refiner Reports Strong Margins

Western Refining, Inc. reported on August 5 that net income of $100.1 million for the second quarter ending June 30, 2011, or $1.10 per basic share and $0.94 per diluted share, compared to second quarter 2010 net income of $14.4 million, or $0.16 per basic and diluted share. The improved results for the quarter were due to stronger refining margins, which were primarily the result of the continued price advantage of WTI crude oil as compared to Brent and other water-borne crude oils.

Jeff Stevens, Western's President and Chief Executive Officer, noted that total refinery throughput averaged approximately 153,000 bpd. "The strong refining margins for inland refineries processing WTI-priced crude oils contributed to our solid earnings in the quarter," said Stevens.

"The Company continues to see strength in the futures market for both distillate and gasoline Gulf Coast crack spreads. Therefore, we are taking the opportunity to lock in these unusually high margins on a portion of our future production by adding to our hedging positions. Capturing these spreads is an important component of our strategy to reduce debt and strengthen our balance sheet," added Stevens. ■

Extension of Construction Start Date Expected for Hyperion Refinery

The South Dakota (USA) state environmental board recently announced it is considering a Texas company's request to extend the construction start deadline for a $10 billion oil refinery planned for southeastern South Dakota.

The state's Board of Minerals and Environment previously approved an air quality permit for Hyperion Resources of Dallas in August 2009, but that permit required construction to begin by February 2011. The company now wants 18 months to start construction from the date a final permit is issued.

The proposed new Hyperion's refinery north of Elk Point, South Dakota (USA) would process 400,000 bpd of Canadian tar sands crude oil each day into low-sulfur gasoline, diesel, jet fuel and LPG. It would be the first new U.S. oil refinery built since 1976. The project would include a gasification-based power plant to supply electricity for the refinery using solid petroleum coke feedstock. ■

Proposed Refinery in North Dakota Acquires Wastewater Discharge Permit

United States Senator John Hoeven said on August 4 that the Environmental Protection Agency (EPA) has approved a key permit for a proposed oil refinery on the Fort Berthold Indian Reservation in the state of North Dakota. Officials say the permit allows for the discharging of treated wastewater from the refining process.

The refinery would process oil from the Bakken Formation in western North Dakota. The 15,000 bpd Mandan, Hidatsa, Arikara (MHA) Nation Clean Fuels Refinery is expected to be one of the few oil refineries to be constructed in the United States in the last 30 years. ■

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Sunoco CEO Discusses Operating Options

Independent refiner Sunoco Inc. Chairman and Chief Executive Lynn Elsenhans said on August 4 that the Philadelphia, Pennsylvania based company "does not have a bullish outlook for refining," during a conference call to analysts to discuss second-quarter returns, in which the Sunoco's refining business lost $44 million. The loss was attributed to multiple equipment failures at its Philadelphia refinery that began in April and lasted into July.

In the short-term Elsenhans said the best option for Sunoco was to continue operating its Philadelphia and Marcus Hook, Pennsylvania, refineries. Since Elsenhans took over as chief executive in 2008, Sunoco has shut one refinery and sold two others. The company also recently spun off its metallurgical coke-producing subsidiary. ■

SAPREF Refinery Preparing for Scheduled Maintenance

South Africa's 180,000 bpd SAPREF in Durban will conduct a routine maintenance in August, the company said on August 5. According to a company spokesman, more details will become available in the month. SAPREF is jointly owned by BP Plc and Royal Dutch Shell. ■

EDITORIALLY SPEAKING

Timing Investments in an Oscillating Business Cycle

Rene Gonzalez, Editor
Refinery Operations

Operational strategies, safety and reliability programs are closely integrated with each other in a business climate where profitability cycles are narrowing while the duration of marginal cycles seem to be widening, even with the advent of more capable technology.

Technical innovations are nonetheless too expensive for some operators. While for others, the "timing" on their investment is off, such as with those who recently changed crude slates without fully taking into account crude characteristics that can lead to levels of corrosion that were not anticipated.

Other processors are well-positioned to invest in new innovations. For example, technology is what provides refiners with competitive flexibility against low demand for some products and relatively higher demand for other products. However, that flexibility is very dependent on the mechanical "availability" of the technology (new or old).

This is one important reason for the relatively long cycle lengths observed in implementation of some new processes and configurations, as uncertainty with regard to the mechanical reliability of the process may not provide the confidence level needed for capital investment. In some areas, such as compressor technology, where there have been significant improvements in turbocompressor performance, the challenge faced by many refiners is due to available capital.

In many cases, it is perceived that "older" technology is better understood and can therefore be more precisely targeted with mechanical reliability strategies that will ensure higher run lengths and less unplanned shutdowns.

This trust in more mature processes helps mitigate the magnitude of the required investment should a decision be made to invest in new technology. For example, a refinery may decide to go forward with a new hydrocracking unit while forgoing with building a new FCCU, which otherwise would seem to be a logical option in Asia and the Middle East for example, where demand for gasoline and petrochemical feedstocks continues to grow.

Interestingly, the onus on finding new ways to leverage mature technology in a down cycle may be one of the reasons that many specialized engineering consulting organizations, staffed by specialists who retired or were laid off from refining companies, are staying quite busy. They are helping certain refiners improve the performance and efficiency of existing assets, rather than building new capacity. For example, in Europe operating efficiency of the largest refineries has been improved to try and remain competitive with Middle Eastern and Indian refineries. However, recent plans to exploit new hydrocarbon resources, such as shale formations in Poland, could predicate capital investment in upgrading technology (e.g., visbreaking, coking, ebullated bed hydrocracking, etc.) for these new feedstocks.

In developing regions, technology licensors and suppliers pursuing large capital projects emphasize that they continue to offer process technology well

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in advance of market requirements and regulatory timetables.

In most cases, the processes that are performing up to expectations from a process development approach are based on collaboration, teamwork and shared benefit. This synergy no doubt fits well in an era where there is a greater need to "manage" processing streams down to the molecular level. ■

Calendar of Events

SEPTEMBER

Sept. 22-23, Russia & CIS Refining Technology Conference & Exhibition, Euro Petroleum Consultants, Moscow, Russia, +44 (0) 20 7357 8394, www.europetro.com.

OCTOBER

Oct. 9-12, NPRA Q&A and Technology Forum, San Antonio, Texas, National Petrochemical & Refiners Association (NPRA), +1 (202) 457 0480, www.npra.org.

Oct. 11-13, Central & Eastern European Refinery & Petrochemicals 14th Annual Meeting, World Refining Association, Gdansk/SOPOT, Poland, +44 (0) 207 067 1818, www.wraconferences.com.

NOVEMBER

Nov. 8-10, Invensys North America OpsManage'11 Conference, Invensys Operations Management, Nashville, Tennessee, USA, opsmanage@invensys.com, www.iom.invensys.com.

Nov. 29 – Dec. 1, ERTC 16th Annual Meeting, Global Technology Forum, Barcelona, Spain, +44 (0) 207 484 9700, www.gtforum.com.

Nov. 29 – Dec. 2, Refinery & Petrochemicals in Russia & the CIS Countries 15th Annual Roundtable, World Refining Association, Geneva, Switzerland, +44 (0) 207 067 1818, www.wraconferences.com.

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METHODOLOGY AND SPECIFICATIONS GUIDE

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ARGUS CRUDE

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LAST UPDATED: JULY 2013

The most up-to-date Argus Crude methodology is available on www.argusmedia.com

Methodology overview

Methodology rationale

Argus strives to construct methodologies that reflect the way the market trades. Argus aims to produce price assessments which are reliable indicators of commodity market values, free from distortion and representative of spot market values. As a result, the specific currencies, volume units, locations and other particulars of an assessment are determined by industry consensus to facilitate seamless bilateral trade and Argus mirrors these industry conventions.

In the global crude markets, Argus reflects physical market prices employing a range of methodologies. These include time stamped bid/ask ranges, averages of deals done in a window, volume-weighted averages of deals done over the entire day as well as cumulative transaction averages across a month and cumulative daily averages. The rationale for each methodology will vary by market.

Argus often applies crude basis differentials to various prices – such as WTI and North Sea Dated – to arrive at fixed prices because this is a representative method of converting differential prices into fixed price assessments

When Argus uses a deals based approach for price identification deals must meet the minimum volume, delivery, timing, and specification requirements in our methodology and the deals must be bona fide. The same requirements apply to most volume-weighted averages.

The time period used to produce representative price indications is that which in the opinion of Argus, following consultation with market participants, can be used to produce a reliable indicator of physical market value.

Argus will announce its publishing schedule in a calendar located at www.argusmedia.com. Argus may not assess prices on certain public holidays even when the exchanges are open, due to anticipated illiquidity in the cash spot markets.

Survey process

Argus price assessments are informed by information received from a wide cross section of market participants, including producers, consumers and intermediaries. Argus reporters engage with the industry by proactively polling participants for market data. Argus will contact and accept market data from all credible market sources including front and back office of market participants and brokers. Argus will also receive market data from electronic trading platforms and directly from the back offices of market participants. Argus will accept market data by telephone, instant messenger, email or other means.

Argus encourages all sources of market data to submit all market data to which they are a party that falls within the Argus stated methodological criteria for the relevant assessment. Argus encourages all sources of market data to submit transaction data from back office functions when and where possible.

Throughout all markets, Argus is constantly seeking to increase the number of companies willing to provide market data. Reporters are mentored and held accountable for expanding their pool of contacts. The number of entities providing market data can vary significantly from day to day based on market conditions. Should the number of entities providing market data repeatedly fall to a level that assessment quality may be affected, supervising editors will review the viability of the assessment.

For certain price assessments identified by local management, should more than 50pc of the market data upon which the assessment is based come from a single entity, then the supervising editor will engage in an analysis of the market data with the primary reporter to ensure that the quality and integrity of the assessment has not been affected.

Argus has committed to deliver many of our final published prices to clients by a particular deadline each day. Because compiling and confirming transactions and other market data in advance of this deadline is a lengthy process, price assessment procedures must be concluded well before that deadline. As a result, Argus has instituted cut-off times for the submission of data by market participants. Argus will review all data received after the cut-off time and will make best efforts to include in the assessment process all verifiable transactions and market data received after the cut-off time but reserves the right to exclude any market data from the process if received after the cut-off time.

Market data usage

In each market, Argus uses the methodological approach deemed to be the most reliable and representative for that market. Argus will utilise various types of market data in its methodologies, to include:

1. Transactions
2. Bids and offers
3. Other market information, to include spread values between grades, locations, timings, and many other data.

In many markets, the relevant methodology will assign a relatively higher importance to transactions over bids and offers, and a relatively higher importance to bids and offers over other market information. Certain markets however will exist for which such a hierarchy would produce unreliable and non-representative price assessments, and so the methodology must assign a different relative importance in order to ensure the quality and integrity of the price assessment. And even in markets for which the hierarchy normally obtains, certain market situations will at times emerge for which the strict hierarchy would produce non-representative prices, requiring Argus to adapt in order to publish representative prices.

Verification of transaction data

Reporters carefully analyse all data submitted to the price assessment process. This data includes transactions, bids, offers, volumes, counterparties, specifications and any other information that contributes materially to the determination of price. This high level

of care applies regardless of the methodology employed. Specific to transactions, bids, and offers, reporters seek to verify the price, the volume, the specifications, location basis, and counterparty. In some transactional average methodologies, reporters also examine the full array of transactions to match counterparties and arrive at a list of unique transactions.

Several tests are applied by reporters in all markets to transactional data to determine if it should be subjected to further scrutiny. If a transaction has been identified as failing such a test, it will receive further scrutiny. For certain price assessments identified by local management, Argus has established internal procedures that involve escalation of inquiry within the source's company and escalating review within Argus management. Should this process determine that a transaction should be excluded from the price assessment process, the supervising editor will initiate approval and, if necessary, documentation procedures.

Primary tests applied by reporters

- Transactions not transacted at arms-length, including deals between related parties or affiliates.
- Transaction prices that deviate significantly from the mean of all transactions submitted for that day.
- Transaction prices that fall outside of the generally observed lows and highs that operated throughout the trading day.
- Transactions that are suspected to be a leg of another transaction or in some way contingent on an unknown transaction.
- Single deal volumes that significantly exceed the typical transaction volume for that market.
- Transaction details that are identified by other market participants as being for any reason potentially anomalous.
- Transaction details that are reported by one counterparty differently than the other counterparty.
- Any transaction details that appear to the reporter to be illogical or to stray from the norms of trading behavior. This could include but is not limited to divergent specifications, unusual delivery location and counterparties not typically seen.
- Transactions that involve the same counterparties, the same price and delivery dates are checked to see that they are separate deals and not one deal duplicated in Argus records.

Secondary tests applied by editors for transactions identified for further scrutiny

Transaction tests

- The impact of linkage of the deal to possible other transactions such as contingent legs, exchanges, options, swaps, or other derivative instruments. This will include a review of transactions in markets that the reporter may not be covering.
- The nature of disagreement between counterparties on transactional details.
- The possibility that a deal is directly linked to an offsetting transaction that is not publicly known, for example a "wash trade" which has the purpose of influencing the published price.
- The impact of non-market factors on price or volume, including distressed delivery, credit issues, scheduling issues, demurrage, or containment.

Source tests

- The credibility of the explanation provided for the outlying nature of the transaction.
- The track record of the source. Sources will be deemed more credible if they
  - Regularly provide transaction data with few errors.
  - Provide data by Argus' established deadline.
  - Quickly respond to queries from Argus reporters.
  - Have staff designated to respond to such queries.
- How close the information receipt is to the deadline for information, and the impact of that proximity on the validation process.

Assessment guidelines

When insufficient, inadequate, or no transaction information exists, or when a transaction based methodology will not produce representative prices, Argus reporters will make an assessment of market value by applying intelligent judgment based on a broad array of factual market information. Reporters must use a high degree of care in gathering and validating all market data used in determining price assessments, a degree of care equal to that applying to gathering and validating transactions. The information used to form an assessment could include deals done, bids, offers, tenders, spread trades, exchange trades, fundamental supply and demand information and other inputs.

The assessment process employing judgment is rigorous, replicable, and uses widely accepted valuation metrics. These valuation metrics mirror the process used by physical commodity traders to internally assess value prior to entering the market with a bid or offer. Applying these valuation metrics along with sound judgment significantly narrows the band within which a commodity can be assessed, and greatly increases the accuracy and consistency of the price series. The application of judgment is conducted jointly with the supervising editor, in order to be sure that guidelines below are being followed. Valuation metrics include the following:

Relative value transactions

Frequently transactions occur which instead of being an outright purchase or sale of a single commodity, are instead exchanges of commodities. Such transactions allow reporters to value less liquid markets against more liquid ones and establish a strong basis for the exercise of judgment.

- Exchange one commodity for a different commodity in the same market at a negotiated value.
- Exchange delivery dates for the same commodity at a negotiated value.
- Exchange a commodity in one location for the same commodity at another location at a negotiated value.

Bids and offers
If a sufficient number of bids and offers populate the market, then the highest bid and the lowest offer can be assumed to define the boundaries between which a deal could be transacted.

Comparative metrics
The relative values between compared commodities are readily discussed in the market and can be discovered through dialogue with market participants. These discussions are the precursor to negotiation and conclusion of transactions.

- Comparison to the same commodity in another market centre.
- Comparison to a more actively traded but slightly different specification commodity in the same market centre.
- Analysis of prices in forward markets for physically deliverable commodity that allow extrapolation of value into the prompt timing for the commodity assessed.
- Comparison to the commodity's primary feedstock or primary derived product(s).
- Comparison to trade in the same commodity but in a different modality (as in barge versus oceangoing vessel) or in a different total volume (as in full cargo load versus partial cargo load).

Throughout this methodology, Argus will explain, in more detail and on a market by market basis, the criteria and procedures that are used to make an assessment of market value by applying intelligent judgment.

Volume minimums and transaction data thresholds
In establishing each methodology, Argus will list specific minimum volume for each assessment. Because of the varying transportation infrastructure found in all commodity markets, Argus typically does not establish thresholds strictly on the basis of a count of transactions, as this could lead to unreliable and non-representative assessments. Instead, minimum volumes are typically established which may apply to each transaction accepted, to the aggregate of transactions, to transactions which set a low or high assessment or to other volumetrically relevant parameters.

For certain price assessments identified by local management, Argus will seek to establish minimum transaction data thresholds and when no such threshold can be established Argus will explain the reasons. These thresholds will often reflect the minimum volumes necessary to produce a transaction-based methodology, but may also establish minimum deal parameters for use by a methodology that is based primarily on judgment.

Should no transaction threshold exist, or should submitted data fall below this methodology's stated transaction data threshold for any reason, Argus will follow the procedures outlined elsewhere in this document regarding the exercise of judgment in the price assessment process.

Transparency and confidentiality
Argus values transparency in energy markets. As a result, we publish lists of deals in our reports that include price, basis, and volume information. The deal tables allow subscribers to cross check and verify the deals against the prices. Argus feels transparency and openness is vital to developing confidence in the price assessment process.

Argus asks for transaction counterparty names from contacts in order to confirm deals and to avoid double-counting in certain volume-weighted averages. In some markets, Argus does not publish counterparty names. In other markets, Argus does publish counterparty names in its reports.

Basis differentials and absolute prices
In the global crude markets, prices are often negotiated bids, offers, and transaction values at differentials to futures prices or to reference prices . Argus fixed prices are derived by adding the assessed differentials to the reference price.

Swaps and forwards markets
Argus publishes forward assessments for numerous markets. These include forward market contracts that can allow physical delivery and swaps contracts that swap a fixed price for the average of a floating published price.

Publications and price data
Argus global crude prices are published in the Argus Crude report. The Argus Americas Crude report contains a subset of these prices. Other Argus publications also include some Argus Americas Crude pricing data. The price data is available independent of the text-based report in electronic files that can feed into various databases. These price data are also supplied through various third-party data integrators. The Argus website also provides access to prices, reports and news with various web-based tools. All Argus prices are kept in a historical database and available for purchase. Contact your local Argus office for information.

Corrections to assessments
Argus will on occasion publish corrections to price assessments after the publication date. We will correct errors that arise from clerical mistakes, calculation errors, or a misapplication of our stated methodology. Argus will not retroactively assess markets based on new information learned after the assessments are published. We make our best effort to assess markets based on the information we gather during the trading day assessed.

Ethics and compliance
Argus operates according to the best practices in the publishing field, and maintains thorough compliance procedures throughout the firm. We want to be seen as a preferred provider by our subscribers, who are held to equally high standards, while at the same

time maintaining our editorial integrity and independence. Argus has a strict ethics policy that applies to all staff. The policy can be found on our website at www.argusmedia.com. Included in this policy are restrictions against staff trading in any energy commodity or energy related stocks, and guidelines for accepting gifts. Argus also has strict policies regarding central archiving of email and instant messenger communication, maintenance and archiving of notes, and archiving of spreadsheets and deal lists used in the price assessment process. Argus publishes prices that report and reflect prevailing levels for open-market arm's length transactions (please see the Argus Global Compliance Policy for a detailed definition of arms length).

Consistency in the assessment process

Argus recognises the need to have judgment consistently applied by reporters covering separate markets, and by reporters replacing existing reporters in the assessment process. In order to ensure this consistency, Argus has developed a program of training and oversight of reporters. This programme includes:

1. A global price reporting manual describing among other things the guidelines for the exercise of judgment.
2. Cross-training of staff between markets to ensure proper holiday and sick leave backup. Editors that float between markets to monitor staff application of best practices.
3. Experienced editors overseeing reporting teams are involved in daily mentoring and assisting in the application of judgment for illiquid markets.
4. Editors are required to sign-off on all price assessments each day, thus ensuring the consistent application of judgment.

Review of methodology

The overriding objective of any methodology is to produce price assessments which are reliable indicators of commodity market values, free from distortion and representative of spot market values. As a result, Argus editors and reporters are regularly examining our methodologies and are in regular dialogue with the industry in order to ensure that the methodologies are representative of the physical market being assessed. This process is integral with reporting on a given market. In addition to this ongoing review of methodology, Argus conducts reviews of all of its methodologies and methodology documents on at least an annual basis.

Argus market report editors and management will periodically and as merited initiate reviews of market coverage based on a qualitative analysis that includes measurements of liquidity, visibility of market data, consistency of market data, quality of market data and industry usage of the assessments. Report editors will review:

- Appropriateness of the methodology of existing assessments
- Termination of existing assessments
- Initiation of new assessments

The report editor will initiate an informal process to examine viability. This process includes:

- Informal discussions with market participants
- Informal discussions with other stakeholders
- Internal review of market data

Should changes, terminations, or initiations be merited, the report editor will submit an internal proposal to management for review and approval. Should changes or terminations of existing assessments be approved, then formal procedures for external consultation are begun.

Changes to methodology

Formal proposals to change methodologies typically emerge out of the ongoing process of internal and external review of the methodologies. Formal procedures for external consultation regarding material changes to existing methodologies will be initiated with an announcement of the proposed change published in the relevant Argus report. This announcement will include:

- Details on the proposed change and the rationale
- Method for submitting comments with a deadline for submissions
- Notice that all formal comments will be published after the given consultation period unless submitter requests confidentiality

Argus will provide sufficient opportunity for stakeholders to analyse and comment on changes, but will not allow the time needed to follow these procedures to create a situation wherein unrepresentative or false prices are published, markets are disrupted, or market participants are put at unnecessary risk. Argus will engage with industry throughout this process in order to gain acceptance of proposed changes to methodology. Argus cannot however guarantee universal acceptance and will act for the good order of the market and ensure the continued integrity of its price assessments as an overriding objective.

Following the consultation period, Argus management will commence an internal review and decide on the methodology change. This will be followed by An announcement of the decision published in the relevant Argus report, to include a date for implementation, publication of stakeholders' comments that are not subject to confidentiality, and Argus' response to those comments.

Updates to methodology

The Argus Crude methodology is constantly updated and revised. The latest available methodology (which may supersede the one you are reading) is available at www.argusmedia.com.

Overview (Argus Crude page 1)

Argus provides an overview of the day's crude market activity, highlighting changes in key crude prices and the price differences among the various regional crudes. The report discusses that day's market activity with particular reference to the main crude benchmark prices. The summary has a global scope, allowing readers to quickly understand the key market drivers.

Pricing tables (Argus Crude page 1)

North Sea, Russia-Caspian, Mediterranean and west Africa

The front page of Argus Crude contains duplicate assessments of the crude prices in the various regional sections. For the North Sea, Russian-Caspian (including fob netbacks) Mediterranean, and West Africa, prices are published as fixed price assessments and also shown as differentials to the benchmarks. The primary benchmark in the Atlantic Basin is Dated, but Dated itself is shown as a differential to the forward North Sea price (the "flat" price). The price methodology for these regions is described in the various regional sections below.

Mideast Gulf

The Mideast Gulf table contains the price assessments made at 4:30pm Singapore time for front month Dubai, front month Oman, and the Abu Dhabi crude Murban.

The Dubai price is published as a fixed price assessment. The Oman price is published as a fixed price assessment and is also shown as a differential to Dubai swaps.

The Murban price is published as a fixed price assessment and also shown as a differential to the Abu Dhabi National Oil Company (Adnoc) OSP.

Asia-Pacific

The Asia-Pacific table contains the price assessments made at 4:30pm Singapore time for Minas, Tapis and North West Shelf crudes.

The Indonesian Minas crude price is published as a fixed price assessment and as a differential to the Indonesian Crude Price (ICP).

Malaysian Tapis crude is published as a fixed price assessment and as a differential to the North Sea Dated and substitute Dated on UK holidays.

Australian North West Shelf condensate is published as a fixed price assessment and as a differential to North Sea Dated, and Substitute Dated on UK holidays (see Asia-Pacific section below).

ESPO Blend is published as a fixed price assessment and as a differential to Dubai swaps.

Sokol is published as a fixed price assessment and as a differential to Dubai swaps for the month of loading.

US pipeline

The US pipeline table contains the prices for LLS, Mars and the *Argus Sour Crude Index™ (ASCI™)* benchmark, LLS, Mars and *ASCI* prices are published as fixed price assessments and as differentials to the front month Nymex WTI settlement price.

Canada pipeline

The Canada pipeline table contains the prices for Canadian Synthetic and WCS, published as fixed price assessments.

Americas cargoes

The Americas cargoes table contains the prices for Nigerian Qua Iboe and Colombian Vasconia, published as fixed price assessments.

Futures markets (Argus Crude page 2)

Argus Crude shows market information from four world futures markets which trade crude oil. These futures exchanges are the London-based IntercontinentalExchange's Brent contract (Ice Brent and Ice Brent NX), the New York Mercantile Exchange's Light Sweet Crude contract (Nymex WTI), the Tokyo-based Tocom Mideast Gulf crude contract and the Dubai Mercantile Exchange's Oman contract.

Argus Crude publishes representative price and market information from the futures exchanges including the Open, High, Low and Settle prices and where possible the estimated volume of trade.

Forward spreads (Argus Crude page 2)

Argus Crude shows the North Sea/Dubai spreads for three months forward, the WTI/North Sea spreads for four months forward and the WTI/Dubai spreads for three months forward, timestamped at 4:30pm London time.

Forward markets (Argus Crude page 3)

The forward markets tables show prices in the forward markets and the intermonth spreads between the different monthly prices. They also show various exchange of futures for physicals prices and exchanges for swaps prices. Various short-term swap price tables are shown. The section also contains pricing components that are used to calculate other Argus price assessments.

North Sea forward Singapore close

The North Sea forward table for Singapore close shows prices for four months forward in the forward North Sea market at 4:30pm Singapore time. This market is the Brent forward market (with Forties, Oseberg or Ekofisk substitutionality). It is called the North Sea forward market in Argus Crude to differentiate it from the 15-day Brent forward market that it replaced. This forward market trades in parallel to the Ice futures market in Brent as an over-the-counter market in Brent.

The contract trades at fixed prices and also in the form of intermonth spreads. *Argus* assesses the prices for the forward North Sea months by applying the intermonth spread assessments to the first-month North Sea forward price. *Argus* uses the EFP differential and the front-month Ice Brent futures to assess first-month forward North Sea, including expiry day, except for the last three sessions in the life of the front-month futures contract. On these sessions, *Argus* uses second-month Ice Brent futures and the corresponding EFP differential (*see Calculating North Sea Dated*).

North Sea forward London close

The forward North Sea London close table duplicates the Dated price and also shows prices for four months forward in the forward North Sea market at 4:30pm London time. This market is the Brent forward market (with Forties, Oseberg or Ekofisk substitutionality). It is called North Sea forward in *Argus Crude* to differentiate it from the 15-day Brent forward market that it replaced. This forward market trades in parallel to the Ice futures market in Brent as an over-the-counter market in Brent. A weighted average of trade on the most liquid forward North Sea month is also the forward (or flat price) used in the calculation of the Dated assessment.

The forward North Sea market trades at fixed prices and also in the form of intermonth spreads. *Argus* assesses the price levels for these intermonth trades in the forward intermonths table on page 4 and uses these intermonth assessments to construct the fixed forward price assessments in the North Sea table.

The BFOE forward contract rolls 28 days before the end of the month (three days to the front of the last loading window and a further 25 days to the last possible nomination date). If this date falls on a weekend or holiday, then the roll date will fall on the previous workday. The last day of trade will be the first workday prior to the roll date.

Dubai Singapore close

Argus quotes forward Dubai for four months forward at 4:30pm Singapore time. A more detailed explanation of the *Argus* Dubai methodology can be found in the Mideast Gulf section or in the Argus document *Argus' Dubai Assessment Methodology* (contact Argus for more details).

The components used in the calculation of the forward Dubai prices are the Dubai/Ice Brent EFS differentials, which *Argus* quotes for three months forward, and the Dubai Intermonths, which *Argus* quotes for three periods forward.

Dubai London close

Argus quotes the forward Dubai price for four months forward. These prices are assessed at London 4:30pm and so differ from the Singapore 4:30pm assessments.

Dated to Ice Brent frontline

Argus quotes prices for the Dated to Frontline (DFL) market which trades the difference between the Dated assessment and the frontline Ice assessment. *Argus* quotes this market for three months forward, two quarters and one year forward. The front DFL month will roll on the 18th of the month, so the front month will be April until the 18th April, after which it will roll to May.

WTI Cushing

WTI is assessed on a cash market basis at 1:30pm Houston time. These prices reflect an intelligent assessment of the bid/ask range at the time stamp. Cash WTI rolls on the fourth business day following the expiry of the front-month Nymex Light Sweet crude futures contract.

North Sea (Argus Crude page 4)

The North Sea crude market is one of the most important oil markets in the world. For many years, the main North Sea crude price was the price of Brent Blend. This was the main price benchmark against which other crudes were valued. In addition to trading physical cargoes, and having other physical grades price against it, the Brent market developed a forward market and also a series of derivative markets, such as short-term contract for differences and long-term swaps. The Brent market is also the underlying market to London-based IntercontinentalExchange's Ice Brent futures contract.

But there was a problem with the Brent Blend benchmark. Production of Brent crude is in decline and the number of freely available cargoes for trade is declining even more rapidly. This means that the benchmark did not always reflect the consensus view of the prevailing market. Consequently, Argus developed the concept of a generic North Sea benchmark which involved broadening the base of liquidity that underpins the benchmark. The generic North Sea benchmarks in Argus Crude evolved over time — from the Argus North Sea Index to the Argus North Sea Reference Price — but eventually the generic benchmark became Argus North Sea Dated, a price derived from a methodology that involved four grades, Brent, Forties, Oseberg and Ekofisk. This price became known as Dated or North Sea Dated.

Calculating North Sea Dated

Argus North Sea Dated is the market's implied value for the North Sea Dated price reference obtained by cross referencing forward trade, CFD trade and physical differentials for the four BFOE crudes within the 10-25 day assessment period.

The building block from which the North Sea Dated assessment is derived is called the "flat" price or "forward" price. It is the price for Brent crude for loading in one (or possibly two) months time.

The forward price is the price for a 25-day North Sea contract (Brent with Forties, Oseberg or Ekofisk substitutionality), a contract that trades forward in monthly delivery periods but which will mature into a physical obligation 25 days in advance of the cargo date nomination.

Argus identifies the "flat" price from a volume weighted average of North Sea forward trade (partial and full cargo) reported to Argus as having transacted between 4:29 and 4:30pm London time. The

Argus North Sea Dated calculation

Date	11-Mar-2013	CFDs		Brent		Forties		Oseberg				Ekofisk			
	Forward N Sea (May)	109.47 CFDs	Anticipated Dated	Dated related	May related	Dated related	May related	Dated related	May related	quality premium	less quality premium	Dated related	May related	quality premium	less quality premium
	Current CFD week	11-Mar-15-Mar													
0	Mon 11-Mar	0.00													
1	Tue 12-Mar	0.00													
2	Wed 13-Mar	0.00													
3	Thu 14-Mar	0.00													
4	Fri 15-Mar	0.00													
5															
6	1st CFD week	18-Mar-21-Mar													
7	Mon 18-Mar	-0.17													
8	Tue 19-Mar	-0.17													
9	Wed 20-Mar	-0.17													
10	Thu 21-Mar	-0.17	109.30	1.20	**110.50**	-0.75	**108.55**	2.05	111.35	0.58	**110.77**	1.70	111.00	0.52	**110.48**
11	Fri 22-Mar	-0.17	109.30	1.20	**110.50**	-0.75	**108.55**	2.05	111.35	0.58	**110.77**	1.70	111.00	0.52	**110.48**
12															
13	2nd CFD week	25-Mar-28-Mar													
14	Mon 25-Mar	-0.12	109.35	1.20	**110.55**	-0.55	**108.80**	2.05	111.40	0.58	**110.82**	1.70	111.05	0.52	**110.53**
15	Tue 26-Mar	-0.12	109.35	1.20	**110.55**	-0.55	**108.80**	2.05	111.40	0.58	**110.82**	1.70	111.05	0.52	**110.53**
16	Wed 27-Mar	-0.12	109.35	1.20	**110.55**	-0.55	**108.80**	2.05	111.40	0.58	**110.82**	1.70	111.05	0.52	**110.53**
17	Thu 28-Mar	-0.12	109.35	1.20	**110.55**	-0.55	**108.80**	2.05	111.40	0.58	**110.82**	1.70	111.05	0.52	**110.53**
18	Fri 29-Mar	-0.12	109.35	1.20	**110.55**	-0.55	**108.80**	2.05	111.40	0.58	**110.82**	1.70	111.05	0.52	**110.53**
19															
20	3rd CFD week	01-Apr-04-Apr													
21	Mon 01-Apr	-0.13	109.34	1.20	**110.54**	-0.15	**109.19**	2.05	111.39	0.68	**110.71**	1.70	111.04	0.59	**110.45**
22	Tue 02-Apr	-0.13	109.34	1.20	**110.54**	-0.15	**109.19**	2.05	111.39	0.68	**110.71**	1.70	111.04	0.59	**110.45**
23	Wed 03-Apr	-0.13	109.34	1.20	**110.54**	-0.15	**109.19**	2.05	111.39	0.68	**110.71**	1.70	111.04	0.59	**110.45**
24	Thu 04-Apr	-0.13	109.34	1.20	**110.54**	-0.15	**109.19**	2.05	111.39	0.68	**110.71**	1.70	111.04	0.59	**110.45**
25	Fri 05-Apr	-0.13	109.34	1.20	**110.54**	-0.15	**109.19**	2.05	111.39	0.68	**110.71**	1.70	111.04	0.59	**110.45**
26															
27	4th CFD week	08-Apr-11-Apr													
28	Mon 08-Apr	-0.23													
29	Tue 09-Apr	-0.23													
30	Wed 10-Apr	-0.23													
31	Thu 11-Apr	-0.23													
32	Fri 12-Apr	-0.23													
Anticipated Dated average for 10 -25 days fwd		May N Sea	**109.34**	Dated Component	**110.54**	Dated Component	**108.92**	Dated Component	111.39		**110.77**	Dated Component	111.04		**110.49**

transaction data threshold in the identification of the North Sea forward physical flat price is 100,000 bl. This has been established following consultation with market participants. In the event of there being less than 100,000 bl of North Sea forward traded in the time period, Argus will establish the flat price as a function of the value of an exchange of futures for physical (EFP) contract and the prevailing Ice Brent futures price.

If Argus assesses the flat price of the forward contracts using an EFP differential and a representative Ice Brent, or Ice Brent NX, futures value then the EFP is assessed throughout the day and the Ice value will usually be the Ice 1 minute marker. The Ice 1 minute marker based on trade at 4:29-4:30pm London time is assumed to be a representative value for the futures contract unless Argus deems otherwise. Argus will deem it otherwise if the Ice 1 minute marker does not appear to be a representative value.

When Argus uses the EFP to assess the flat price Argus uses the EFP differential and the front-month Ice Brent futures. In the last three sessions in the life of the front-month futures contract Argus uses second-month Ice Brent futures and the corresponding EFP differential.

A full roll date calendar is available on www.argusmedia.com

The North Sea crude prices used in the Dated methodology are assessed either against the anticipated value of Dated or against the flat (forward) price depending on which formulas are under discussion by the market. The market often uses the anticipated Dated value as a reference because it is common that crude grades will price against the value of Dated at the date of loading. The market anticipates the value of Dated, for risk management purposes, by trading contracts for difference (CFDs) between the forward price and the anticipated value of Dated. Argus can construct the market's perceived value of Dated several weeks forward from these CFD prices. Argus uses these CFD values to publish an Anticipated Dated value which is an average of the prices 10-25 days forward as anticipated by the market for Dated.

Prices for the four leading grades of North Sea crude, Brent, Forties, Oseberg and Ekofisk, are valued either against the forward (or flat) price of Brent or against the anticipated Dated value at the time of loading. Argus will use one or both of these sets of differentials to construct the prices for Brent, Forties, Oseberg and Ekofisk in the 10-25 days forward period. A quality premium will be deducted from the prices for Ekofisk and Oseberg in the 10-25 days forward period, starting with cargoes loading from June 2013 onwards.

Ekofisk and Oseberg quality premiums

Argus will publish quality premiums for Oseberg and Ekofisk for cargoes loading from June 2013 onwards. The quality premiums will be taken into account in the Argus North Sea Dated assessment process.

Argus will publish the relevant quality premiums for Oseberg and Ekofisk on the first publishing day of each month, starting 1 May 2013. The quality premium will be applied to cargoes loading in the following month. For example, the quality premium announced on 1 May 2013 will be applied to June loading cargoes.

The quality premium for Oseberg and Ekofisk will be calculated according to the formula laid out in amendment M of Shell's Suko-90 contract. For example, the quality premium for Oseberg will be calculated at 50pc of the sum of two-thirds of the average price difference between Oseberg and the most competitive BFOE grade in the second month prior to the month of loading, plus one-third of the average price difference between Oseberg and the most competitive BFOE grade during the third month prior to the loading month. If the quality premium falls below 25¢/bl, no quality premium will be applied.

The quality premium for Ekofisk will be calculated at 50pc of the sum of two-thirds of the average price difference between Ekofisk and the most competitive BFOE grade in the second month prior to the month of loading, plus one-third of the average price difference between Ekofisk and the most competitive BFOE grade during the third month prior to the loading month. If the quality premium falls below 25¢/bl, no quality premium will be applied.

The relevant quality premiums will be deducted from Oseberg and Ekofisk assessments for cargoes loading from June 2013 onwards as they are captured within the Argus 10-25 day forward period. An average of the prices in the 10-25 day forward period will be used to determine the Oseberg (with quality premium applied) and Ekofisk (with quality premium applied) components as well as the Brent and Forties components in the Argus North Sea Dated methodology. The lowest of the Brent, Forties, Oseberg (with quality premium applied) and Ekofisk (with quality premium applied) components will set the Dated price.

North Sea Dated (with no quality premium applied)

Argus will continue to run a price series based on the North Sea Dated methodology above but without any quality premium being applied until further notice. This price series will be called Dated BFOE and can be found on p4 of the Argus Crude Report.

The 10-25 day average is determined by industry convention.

This methodological approach used by Argus is also utilised by all active participants in the North Sea market to identify the value of Dated. Argus identifies CFD and EFP values by using an assessment of a reasonable bid and offer range at the close of market.

Argus assesses the physical grade differential for each day of the 10-25 day assessment period for Brent, Forties, Oseberg and Ekofisk. Argus identifies the physical price differentials at 4:30pm for each loading date which has market depth at 4:30pm and will use information gathered throughout the day to make inferred price assessments for every other loading day of the 10-25 day assessment period. The lowest average of the daily assessments for the four crudes in the North Sea Dated methodology will then set the North Sea Dated value.

Argus uses the Argus North Sea Dated Calculation spreadsheet (*see above*) to construct the North Sea Dated assessment. The spreadsheet illustrates how *Argus* assesses prices for each of the Brent, Forties, Oseberg and Ekofisk crude grades on each individual working day in the 10-25 day assessment period. The spreadsheet shows how Argus takes into account market structure when transactions for loading dates in the 10-25 assessment period occur in close time proximity.

Argus will ensure that confirmed market information will be placed on the Argus Crude Oil Bulletin Board during the day, and guarantees to do this in a timely manner between 3:30pm and 4:30pm London time.

Argus uses inferred price assessments based on information gathered throughout the day because there is insufficient market activity at 4:30pm to construct a bid/offer price for every grade for each loading day within the price assessment period. *Argus* does not rigidly use the highest bid at 4:30pm for a single loading date in the 10-25 assessment period to set the prices for all dates in this assessment period. Using highest bids for a single loading day may lever the entire 10-25 day assessment period in a manner that is not considered representative by the market. Neither does Argus weight the assessment according to transactions at any particular time during the day, nor does it average transactions to identify a price level for North Sea Dated.

The North Sea Dated assessment is the benchmark price against which other grades of crude oil are assessed in the Atlantic basin.

North Sea assessments

Dated or **North Sea Dated** is set by the lowest of the Brent, Forties, Oseberg (with quality premium applied) and Ekofisk (with quality premium applied) components. Consequently it is not the price of a grade of crude but a benchmark established through a methodology. Therefore it has no API density or sulphur specification.

North Sea Assessments

Grade	typical °API	typical Sulphur %	Basis/Location	Timing	Cargo size
Dated			fob Sullom Voe, Hound Point, Teesside, UK or Sture terminal	Loading 10-25 days ahead	600,000 bl
Brent	37.9	0.45	fob Sullom Voe	Loading 10-25 days ahead	600,000 bl
Forties	40.3	0.56	fob Hound Point, UK	Loading 10-25 days ahead	600,000 bl
Oseberg	37.8	0.27	fob Sture terminal	Loading 10-25 days ahead	600,000 bl
Ekofisk	37.5	0.23	fob Teesside, UK	Loading 10-25 days ahead	600,000 bl
Statfjord cif Rotterdam	39.1	0.22	cif Rotterdam	Loading 10-25 days ahead	855,000 bl
Statfjord fob platform	39.1	0.22	fob platform	Loading 10-25 days ahead	855,000 bl
Gullfaks cif Rotterdam	36.2	0.26	cif Rotterdam	Loading 10-25 days ahead	855,000 bl
Gullfaks fob platform	36.2	0.26	fob platform	Loading 10-25 days ahead	855,000 bl
Flotta	36.9	0.82	fob Flotta terminal	Loading 10-25 days ahead	650,000 bl

The prices for the various grades of crude oil are established by adding the current Dated price to the current market differential for that grade of crude. *Argus* assesses the grade differentials during the course of the day with a cutoff time at 4:30pm London time. Formulas for Dated-related crudes are an indication of the differential to Dated around bill of lading assessed as achievable on the day of the report. Argus does not consider ship-to-ship transfers when assessing the grade differentials.

Argus also publishes the component values for Brent, Forties, Oseberg (with quality premium applied) and Ekofisk (with quality premium applied) that are used to calculate the price of Dated. It is the lowest of these four components that sets the price of Dated. The component values for these crudes are not necessarily the same as the prices for these crudes, as the grade prices are calculated by adding the market premium for the grade to the current Dated value.

The **Brent** assessment is the price of Brent Blend, a North Sea crude. The value of Brent is calculated by applying the market differential of Brent to the current Dated value. The prevailing market differential is also published separately.

The **Forties** assessment is the price of Forties Blend, a North Sea crude. The value of Forties is calculated by applying the market differential of Forties to the current Dated value. The prevailing market differential is also published separately.

The **Oseberg** assessment is the price of Oseberg, a North Sea crude. The value of Oseberg is calculated by applying the market differential of Oseberg to the current Dated value. The prevailing market differential is also published separately.

The **Ekofisk** assessment is the price of Ekofisk, a North Sea crude. The value of Ekofisk is calculated by applying the market differential of Ekofisk to the current Dated value. The prevailing market differential is also published separately.

The **Statfjord cif Rotterdam** assessment is the price of Statfjord, a North Sea crude. The value of Statfjord cif Rotterdam is calculated by applying the market differential of Statfjord cif Rotterdam to the current Dated value. The prevailing market differential is also published separately. Statfjord is an offshore crude loaded at the platform rather than at an onshore terminal.

The **Statfjord fob platform** assessment is the price of Statfjord, a North Sea crude. The value of Statfjord fob platform is calculated by applying the market differential of Statfjord fob platform to the current Dated value. The prevailing market differential is also published separately. No modifications are made to the prevailing premium or discount in respect of freight arrangements.

The **Gullfaks cif Rotterdam** assessment is the price of Gullfaks, a North Sea crude. The value of Gullfaks cif Rotterdam is calculated by applying the market differential of Gullfaks cif Rotterdam to the current Dated value. The prevailing market differential is also published separately. Gullfaks is an offshore crude loaded at the platform rather than at an onshore terminal.

The **Gullfaks fob platform** assessment is the price of Gullfaks, a North Sea crude. The value of Gullfaks fob platform is calculated by applying the market differential of Gullfaks fob platform to the current Dated value. The prevailing market differential is also published separately. No modifications are made to the prevailing premium or discount in respect of freight arrangements.

The **Flotta** assessment is the price of Flotta, a North Sea crude. The value of Flotta is calculated by applying the market differential of Flotta to the current Dated value. The prevailing market differential is also published separately.

North Sea EFP

Argus quotes the North Sea EFP, or the exchange of futures for physical price, which is the traded differential between the Ice Brent futures contract and the equivalent month North Sea forward price.

Ice Bwave

Argus also shows the Bwave price for three months forward. This is a weighted average of trade on the Ice Brent contract on the previous working day as calculated by the IntercontinentalExchange. It is used as a component in the Saudi Aramco formula for crude sales into Europe. Argus shows the Saudi Formula Base price which is derived from the Bwave that is the underlying price in its sales formula to European customers. The same formula is used by Kuwait and Iran in sales to European customers.

Ice minute markers

Argus shows the Ice 1 minute marker price which is a weighted average of trade on the Ice Brent contract between 4:29 and 4:30pm for two months forward as calculated by the IntercontinentalExchange.

Dated CFDs

Argus quotes prices for North Sea Dated CFDs, timestamped at 12:00pm and at 4:30pm London time. These are contracts for difference (or short-term swaps) for Dated against forward North Sea contracts. These North Sea Dated CFD prices are expressed as differentials to forward North Sea for four weekly periods forward.

Intermonths

The forward North Sea market rarely trades at fixed prices. Instead, most trade is in the form of intermonth trades. Argus assesses the price levels for these intermonth trades in the forward intermonths table and uses these intermonth assessments to construct the fixed forward price assessments in the North Sea table on page 3.

North Sea calculations

The North Sea calculations table shows how the component parts of Dated are used to derive the benchmark price.

North Sea basis (flat price) is a weighted average of forward North Sea trade in the minute leading up to 4:30pm London time. In the absence of reported trade, the Ice Brent, or Ice Brent NX, minute marker and an EFP are used.

Anticipated Dated was previously called Argus Synthetic BFO. It is an average of the prices 10-25 days forward that are anticipated by the market for Dated as derived from the CFD market.

The **Brent, Forties, Oseberg (with quality premium applied) and Ekofisk (with quality premium applied) components** are the average prices 10-25 days forward using the Argus Dated methodology. The lowest of these components sets Argus Dated (*see Calculating North Sea Dated*).

Argus alternative Dated illustrations

Argus publishes a number of alternative Dated illustrations: **Argus Dated Average** (an average of the Brent, Forties, Oseberg and Ekofisk components), **Argus Dated BFOE** (equivalent to *Argus* North Sea Dated with no quality premiums applied), **Argus Dated BFO** (set by the lowest priced of the Brent, Forties and Oseberg components), and **Argus Dated FOE** (set by the lowest priced of the Forties, Oseberg and Ekofisk components).

Argus North Sea Reference Price

Argus also publishes a second North Sea generic price called the ***Argus* North Sea Reference Price**. This was a precursor to Argus Dated. The Argus North Sea Reference Price uses a forward curve similar to Anticipated Dated called Synthetic Brent.

The *Argus* North Sea Reference Price is based on a weighted average of adjusted North Sea crude assessments. The North Sea crude assessments are standardised using the Argus Synthetic Brent assessment, which is calculated from the market relevant Argus North Sea forward price adjusted by the average value of the second and third week CFD (contract for differences) value as published in Argus Crude. This average is weighted between the second and third week according to the number of working days in the second and third weeks that fall 15 to 19 days ahead of the current date. The weighted average of the North Sea crude assessments (Forties, Flotta, Ekofisk, Statfjord and Oseberg prices) used in the Argus North Sea Reference Price is composed of the following ratio:

	Ratio	Approx %
Forties	25	26.32
Flotta	5	5.26
Ekofisk	15	15.79
Oseberg	15	15.79
Statfjord	35	36.84

The assessments for these crudes are calculated by appying the differential of the market value of the crude against the *Argus* Synthetic Brent price.

The **Argus Synthetic Brent** assessment is calculated from the relevant Argus North Sea forward price adjusted by the average value of the second and third week CFD (contract for difference) value as published in Argus Crude. It is a component of the Argus North Sea Reference Price.

Russia-Caspian (Argus Crude page 6)

Argus assesses the price for a variety of Russian and Caspian crudes transported by ship to Rotterdam and Augusta, Italy, and by pipeline to central Europe. Argus also calculates netback values to the loading terminals for several crudes.

Russian and Caspian crude prices are calculated using the differentials to the current Dated price. The methodology behind the Dated assessment can be found in the North Sea section and on the www.argusmedia.com. The grade differentials are assessed during the course of the day with a cut off at 5:30pm London time. The current differentials and current Dated assessments are added together to generate the grade assessment.

Argus conducts quarterly surveys of market participants and surveyors as well as using quality certificates for loaded cargoes to ascertain average Urals gravity and sulphur content over the quarter. The average arrived at by this method will be applied to crude loading in the following quarter. The quality to be applied in the upcoming quarter will be announced one week before the start of the quarter.

Urals (Russian Export Blend) cif assessments assume an EU-standard double-hulled vessel.

The timing of the price assessments varies according to quotation. Check Russian-Caspian assessments table below for each assessment's timing period.

The Druzhba prices are assessed for Russian export blend at first point of export for delivery at various locations along the Druzhba (Friendship) pipeline. The prices are for 30,000 tonne tranches and for balance of the month. The market survey is conducted among Russian producers, shippers and end-user refineries. In the event that the market takes on retrospective pricing, the assessment price is the perceived value of the differential that will eventually be agreed between the seller and buyer for the month's oil.

Russian-Caspian assessments

The **Urals NWE** assessment is the price of Urals, or Russian export blend crude. The value of Urals NWE is calculated by applying the market differential of Urals cif northwest Europe to the Dated value. The prevailing market differential is also published separately.

The **Urals Med 80,000t** assessment is the price of Urals, or Russian export blend crude. The value of Urals Med is calculated by applying the market differential of Urals cif Augusta to the current Dated value. The prevailing market differential is also published separately. The Urals cif Augusta assessment reflects the market price of 80,000t cargoes.

The **Urals Med 135,000t** assessment is the price of Urals, or Russian export blend crude. The value of Urals Med is calculated by applying the market differential of Urals cif Augusta to the current Dated value. The prevailing market differential is also published separately. The Urals cif Augusta assessment reflects the market price of 135,000t cargoes.

The **Siberian Light** assessment is the price of Siberian Light, a Russian export blend. The value of Siberian Light is calculated by applying the market differential of Siberian Light cif Augusta to the current Dated value. The prevailing market differential is also published separately.

The **CPC Blend** assessment is the price of CPC Blend, a Kazakh export blend. The value of CPC Blend is calculated by applying the market differential of CPC Blend cif Augusta to the current Dated value. The prevailing market differential is also published separately.

The **Tengiz** assessment is the price of Tengiz, a Kazakh crude. The value of Tengiz is calculated by applying the market differential of Tengiz cif Augusta to the current Dated value. The prevailing market differential is also published separately.

The **BTC** assessment is the price of BTC origin crude. BTC is the Baku-Tbilisi-Ceyhan pipeline which has its terminal at Ceyhan, Turkey. The value of the BTC crude is calculated by applying the market differential of BTC cif Augusta to the current Dated value. The prevailing market differential is also published separately.

The **Azeri Light** assessment is the price of Azeri Light, a crude from Azerbaijan. The value of Azeri Light is calculated by applying the market differential of Azeri Light cif Augusta to the current Dated value. The prevailing market differential is also published separately.

The **Urals fob Primorsk** netback is calculated from the price of Urals NWE, netted back to Primorsk. The Urals Primorsk fob netback is derived from the Urals cif northwest Europe assessment netted back for freight, insurance and ice/towage fees. The freight cost is for 100,000t vessels and is assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). The ice/towage fees are calculated in roubles/GT and converted into dollars/bl. Insurance costs are calculated as a percentage of the outright cif price. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure. The netback also does not include the additional fixed rate differential added for voyages within the Baltic and North Sea Sulphur Oxide Emissions Control Area (SECA) as mentioned by Worldscale. There is a "Rotterdam charge" of $1.10/t added to the freight cost, assuming standard cargo sizes of 100,000t and vessels with gross tonnage of 60,000GT.

The **Urals fob Ust-Luga** netback is calculated from the price of Urals NWE, netted back to Ust-Luga. The Urals Ust-Luga fob netback is derived from the Urals cif northwest Europe assessment netted back for freight, insurance and ice/towage fees. The freight cost is for 100,000t vessels and is assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). The ice/towage fees are calculated in roubles/GT and converted into dollars/bl. Insurance costs are calculated as a percentage of the outright cif price. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure. The netback also does not include the additional fixed rate differential added for voyages within the Baltic and North Sea Sulphur Oxide Emissions Control Area (SECA) as mentioned by Worldscale. There is a "Rotterdam charge" of $1.10/t added to the freight cost, assuming stand-

Russian-Caspian assessments

Grade	Typical °API	Typical Sulphur %	Conversion factor t/bl	Basis/Location	Timing	Cargo size
Urals NWE	31.25	1.33	7.2347	cif northwest Europe	Loading 10-25 days ahead	100,000t
Urals Med 80,000t	30.97	1.22	7.2223	cif Augusta, Italy	Loading 10-25 days ahead	80,000t
Urals Med 135,000t	30.97	1.22	7.2223	cif Augusta, Italy	Loading 10-25 days ahead	135,000t
Siberian Light	35.28	0.50	7.4139	cif Augusta, Italy	Loading 10-25 days ahead	75,000t
CPC Blend	45.80	0.55	7.8815	cif Augusta, Italy	Loading 10-30 days ahead	80,000t -135,000t
BTC	36.74	0.18	7.4786	cif Augusta, Italy	Loading 15-35 days ahead	80,000t-135,000t
Tengiz	47.20	0.55	7.9438	cif Augusta, Italy	Loading 10-30 days ahead	80,000t
Azeri Light	35.53	0.15	7.425	cif Augusta, Italy	Loading 15-35 days ahead	80,000t-135,000t
Urals fob Primorsk	31.25	1.33	7.2347	fob Primorsk, Baltic		100,000t
Urals fob Ust-Luga	31.09	1.55	7.2277	fob Ust-Luga, Baltic		100,000t
Urals fob Novorossiysk 80,000t	30.97	1.22	7.2223	fob Novorossiysk, Black Sea		80,000t
Urals fob Novorossiysk 135,000t	30.97	1.22	7.2223	fob Novorossiysk, Black Sea		135,000t
Urals cif Black Sea 80,000t	30.97	1.22	7.2223	cif Black Sea		80,000t
CPC Terminal	45.80	0.55	7.8815	fob CPC terminal, near Novorossiysk		135,000t
Tengiz	47.20	0.55	7.9438	fob Odessa		80,000t
BTC	36.74	0.18	7.4786	fob Ceyhan		80,000t
Azeri Light	35.53	0.15	7.425	fob Supsa		80,000t
Druzhba Czech Republic	31.08	1.56	7.2272	fit Budkovce, Slovakia (for Czech delivery)	Delivered during balance of current month	10,000t tranche
Druzhba Slovakia	31.08	1.56	7.2272	fit Budkovce, Slovakia (for Slovak delivery)	Delivered during balance of current month	10,000t tranche
Druzhba Hungary	31.08	1.56	7.2272	fit Fenyeslitke, Hungary (for Hungarian delivery)	Delivered during balance of current month	10,000t tranche
Druzhba Poland	31.08	1.56	7.2272	fit Adamowo, Poland (for Polish delivery)	Delivered during balance of current month	10,000t tranche
Druzhba Germany	31.08	1.56	7.2272	fit Adamowo, Poland (for German delivery)	Delivered during balance of current month	10,000t tranche

ard cargo sizes of 100,000t and vessels with gross tonnage of 60,000GT.

The **Urals 80,000t fob Novorossiysk** netback is calculated from the price of Urals Med, netted back to Novorossiysk. The Urals Novorossiysk fob netback is derived from the Urals cif Mediterranean assessment netted back for freight, insurance and demurrage costs. The freight cost is for 80,000t vessels and is assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). Insurance costs are calculated as a percentage of the outright cif price. Demurrage costs are assessed daily and multiplied by the number of days delay in both directions, north bound and south bound, in the Turkish Straits above two days. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure.

The **Urals 135,000t fob Novorossiysk** netback is calculated from the price of Urals Med, netted back to Novorossiysk. The Urals Novorossiysk fob netback is derived from the Urals cif Mediterranean assessment netted back for freight, insurance and demurrage costs. The freight cost is for 135,000t vessels and is assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). Insurance costs are calculated as a percentage of the outright cif price. Demurrage costs are assessed daily and multiplied by the number of days delay in both directions, north bound and south bound, in the Turkish Straits above two days. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure.

The **Urals 80,000t cif Black Sea** netback is calculated from the Urals fob Novorossiysk netback index with added freight costs to the Black Sea ports of Constantza/Media (Romania) and Burgas (Bulgaria). The Urals Novorossiysk fob netback is derived from the Urals cif Mediterranean assessment netted back for freight, insurance and demurrage costs. The freight cost is for 80,000t vessels and is assessed daily based on Black Sea-Med spot freight rates from the Argus Freight report applied to average flat rate for Novorossiysk-Constantza and Novorossiysk-Burgas routes (see Argus Freight methodology). Insurance costs are calculated as a percentage of the cif Black Sea price. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure.

The **CPC Blend fob Terminal** netback is calculated from the price of CPC Blend, netted back to the CPC terminal near Novorossiysk, adjusted for other costs. The CPC Terminal fob netback is derived from the CPC Blend cif Augusta assessment netted back for freight, insurance and demurrage costs. The freight cost is for 135,000t vessels and is assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). Insurance costs are calculated as a percentage of the outright cif price. Demurrage costs are assessed daily and multiplied by the number of days delay in both directions, north bound and south bound, in the Turkish Straits above two days. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure. There is a CPC Terminal discount of $1.42/t on the freight cost, which is regularly adjusted.

The **Tengiz fob Odessa** netback is calculated from the price of Tengiz, netted back to Odessa, adjusted for other costs. The Odessa fob netback is derived from the Tengiz cif Augusta assessment netted back for freight, insurance and demurrage costs. The freight cost is for 80,000t vessels and is assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). Insurance costs are calculated as a percentage of the outright cif price. Demurrage costs are assessed daily and multiplied by the number of days delay in both directions, north bound and south bound, in the Turkish Straits above two days. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure.

The **BTC fob Ceyhan** quotation is an assessment but in the absence of strong trading indications will be based on a BTC fob netback derived from the BTC cif Augusta assessment netted back for freight and insurance costs. The freight cost will be for 80,000t vessels and will be assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). Insurance costs are calculated as a percentage of the outright cif price.

The **Azeri Light fob Supsa** netback is calculated from the price of Azeri Light, netted back to Supsa, adjusted for other costs. The Azeri Light fob netback is derived from the Azeri Light cif Augusta assessment netted back for freight, insurance and demurrage costs. The freight cost is for 80,000t vessels and is assessed daily based on spot freight rates from the Argus Freight report (see Argus Freight methodology). Insurance costs are calculated as a percentage of the outright cif price. Demurrage costs are assessed daily and multiplied by the number of days delay in the Turkish Straits above two days. The netback does not include transportation losses, ballast, port demurrage, commissions, bank loan expenses or market structure.

Russia-Caspian retrospective assessments

These assessments are based on the publication date's North Sea Dated added to the average of the fob differentials published over the retrospective period during which cargoes for loading that day are likely to have traded. They give the approximate price that a cargo loading on the day of publication could be expected to achieve.

The **Urals fob Primorsk retrospective** assessment is based on the publication date's North Sea Dated added to the average of the Urals fob Primorsk differentials for working days in a 10-25 day period before the publication date.

The **Urals fob Ust-Luga retrospective** assessment is based on the publication date's North Sea Dated added to the average of the Urals fob Ust-Luga differentials for working days in a 10-25 day period before the publication date.

The **Urals fob Novorossiysk (80kt) retrospective** assessment is based on the publication date's North Sea Dated added to the average of the Urals fob Novorossiysk differentials for working days in a 10-25 day period before the publication date.

The **CPC Blend fob CPC Terminal retrospective** assessment

is based on the publication date's North Sea Dated added to the average of the CPC Blend fob CPC Terminal differentials for working days in a 10-30 day period before the publication date.

Druzhba pipeline prices

Argus publishes weekly and monthly price assessments for inland deliveries of Russian Urals crude to refineries in eastern Europe by the Druzhba (Friendship) pipeline. Prices reflect most competitive spot and term deals between last Russian seller and first independent buyer — trader or refiner. Argus attempts to establish a buy-sell range based on the lowest price level of the market. Prices on the Druzhba line are usually established in the first week of a month for the past month's supplies.

Monthly price assessments are derived retrospectively from prices agreed between buyers and sellers to determine the differential to North Sea Dated based on formulas linking Druzhba and seaborne Urals prices. The monthly differentials emerge at the beginning of the following month. So the July differentials to Dated for Druzhba appear at the beginning of August. Argus assesses the average monthly differential to Dated for different locations on the Druzhba pipeline. These are combined with an average of Dated values over the appropriate month to give an outright price.

Weekly price assessments reflect traders' expectations of rolling average differentials to North Sea Dated from the beginning of each month. The differentials for the previous week are updated every Friday and applied daily to the current Dated price.

The Druzhba Czech Republic assessment is the price of Urals fit Budkovce for delivery to the Czech Republic along the Druzhba pipeline at first point of export. The value of Druzhba Czech Republic is calculated by applying the market differential of Druzhba Czech Republic to the Dated value for the day of publication (weekly) or previous month (monthly). The prevailing market differential is also published separately.

The Druzhba Slovakia assessment is the price of Urals fit Budkovce for delivery to Slovakia along the Druzhba pipeline at first point of export. The value of Druzhba Slovakia is calculated by applying the market differential of Druzhba Slovakia to the Dated value for the day of publication (weekly) or previous month (monthly). The prevailing market differential is also published separately.

The Druzhba Hungary assessment is the price of Urals fit Fenyeslitke for delivery to Hungary along the Druzhba pipeline at first point of export. The value of Druzhba Hungary is calculated by applying the market differential of Druzhba Hungary to the Dated value for the day of publication (weekly) or previous month (monthly). The prevailing market differential is also published separately.

The Druzhba Poland assessment is the price of Urals fit Adamowo for delivery to Poland along the Druzhba pipeline at first point of export. The value of Druzhba Poland is calculated by applying the market differential of Druzhba Poland to the Dated value for the day of publication (weekly) or previous month (monthly). The prevailing market differential is also published separately.

The Druzhba Germany assessment is the price of Urals fit Adamowo for delivery to Germany along the Druzhba pipeline at first point of export. The value of Druzhba Germany is calculated by applying the market differential of Druzhba Germany to the Dated value for the day of publication (weekly) or previous month (monthly). The prevailing market differential is also published separately.

Cif basis Singapore assessments

The **BTC Blend cif basis Singapore** assessment is calculated by adding a freight component to the BTC fob Ceyhan assessment. The freight cost is for 135,000t vessels and is assessed daily based on spot Med/Black Sea–East freight rates from the *Argus Freight report.*

The **Urals Black Sea cif basis Singapore** assessment is calculated by adding a freight component to the Urals fob (135kt) Novorossiysk netback. The freight cost is for 135,000t vessels and is assessed daily based on spot Med/Black Sea–East freight rates from the *Argus Freight report*.

Mediterranean (Argus Crude page 8)

Argus assesses a variety of sweet and sour grades of crude in the Mediterranean. The crudes chosen are not only those for which there is open spot market activity but also those that allow price comparisons on sulphur and other specifications. The published prices are not meant to be official selling prices. Official selling prices will also be published in Argus Crude and clearly labelled as such.

Mediterranean crude prices are calculated using the differentials to the current North Sea Dated price. The methodology behind the Dated assessment can be found in the North Sea section and on www.argusmedia.com. The grade differentials are assessed during the course of the day with a cut off time at 5:30pm London time. The current differentials and current Dated assessments are added together to generate the grade assessment.

The timing of the price assessments is for an average price in the period 10–25 days ahead except for Kirkuk which is for an average of 5-15 days ahead.

Mediterranean assessments

The value of **Saharan Blend**, an Algerian crude, fob Arzew, is calculated by applying the market differential of Saharan Blend to the current Dated value. The prevailing market differential is also published separately.

The value of **Zarzaitine**, an Algerian crude, fob Tunisia, is calculated by applying the market differential of Zarzaitine to the current Dated value. The prevailing market differential is also published separately.
The value of **Es Sider,** a Libyan crude, fob Libya, is calculated by applying the market differential of Es Sider to the current Dated value. The prevailing market differential is also published separately.

The value of **Kirkuk**, an Iraqi crude, fob Ceyhan, is assessed in relation to other quoted crude prices in the Mediterranean. The prevailing market differential to the Dated value is also published separately.

The value of **Basrah Light**, an Iraqi crude, fob Sidi Kerir, is calculated by applying the market differential of Basrah Light to the current Dated value. The prevailing market differential is also published separately.

The value of **Iran Light**, an Iranian crude, fob Sidi Kerir is assessed using the official formula price, the prevailing Dated-to-Frontline (DFL) value (the difference between North Sea Dated and Ice Brent futures on a calendar month basis) for the appropriate month and changes in the value of the Mediterranean Urals 80,000t quote. The prevailing market differential to the Dated value is also published separately.

The value of **Iran Heavy**, an Iranian crude, fob Sidi Kerir, is assessed using the official formula price, the prevailing Dated-to-Frontline (DFL) value (the difference between North Sea Dated and Ice Brent futures on a calendar month basis) for the appropriate month and changes in the value of the Mediterranean Urals 80,000t quote. The prevailing market differential to the Dated value is also published separately.

The value of **Suez Blend**, an Egyptian crude, fob Ras Shukeir, is assessed using the official formula price and changes to the Mediterranean Urals 80,000t quote. The prevailing market differential to the Dated value is also published separately.

Official formula prices

Argus also publishes official formula prices for crude from Algeria, Syria, Libya and Egypt. These are expressed as differentials to Dated or Urals in the Mediterranean for a given loading month and are set by national oil companies.

Mediterranean assessments

Grade	typical °API	Typical Sulphur %	Basis/ Location	Timing	Cargo size
Saharan Blend	46.0	0.10	fob Arzew	Loading 15-35 days ahead	80,000t - 130,000t
Zarzaitine	42.8	0.06	fob La Skhirra	Loading 10-25 days ahead	80,000t - 130,000t
Es Sider	36.2	0.49	fob Libya	Loading 10-25 days ahead	80,000t - 130,000t
Kirkuk	36	2.00	fob Ceyhan	Loading 10-25 days ahead	80,000t - 130,000t
Basrah Light	30.0	2.92	fob Sidi Kerir	Loading 10-25 days ahead	80,000t - 130,000t
Iran Light	33.7	1.50	fob Sidi Kerir	Loading 10-25 days ahead	80,000t - 130,000t
Iran Heavy	30.7	1.80	fob Sidi Kerir	Loading 10-25 days ahead	80,000t - 130,000t
Suez Blend	30.4	1.65	fob Ras Shukeir	Loading 10-25 days ahead	80,000t - 130,000t

West Africa (Argus Crude page 9)

Argus assesses a variety of west African crudes. The crudes chosen are not only those for which there is open spot market activity but also those that allow price comparisons among the various grades. The published prices are not meant to be official selling prices. Official selling prices will also be published in Argus Crude and clearly labelled as such.

West African crude prices are calculated using the differentials to the current North Sea Dated price. The methodology behind the Dated assessment can be found in the North Sea section and on www.argusmedia.com. The grade differentials are assessed during the course of the day with a cut off time at 5:30pm London time. The current differentials and current Dated assessments are added together to generate the grade assessment. The timing of the Nigerian price assessments is for an average price in the period 20-45 days ahead. The timing of the Angolan price assessments is for an average price in the period 25-60 days ahead.

The formula price published represents the premium or discount to Dated around bill of lading assessed as achievable in the current market and used when establishing the quotation, except for Nigerian cargoes which are assessed five days after the bill of lading (the same pricing basis used by NNPC).

West Africa assessments

The value of **Agbami**, a Nigerian crude, is calculated by applying the market differential of Agbami to the current Dated value. The prevailing market differential is also published separately.

The value of **Amenam**, a Nigerian crude, is calculated by applying the market differential of Amenam to the current Dated value. The prevailing market differential is also published separately.

The value of **Bonga**, a Nigerian crude, is calculated by applying the market differential of Bonga to the current Dated value. The prevailing market differential is also published separately.

The value of **Bonny Light**, a Nigerian crude, is calculated by applying the market differential of Bonny Light to the current Dated value. The prevailing market differential is also published separately.

The value of **Brass River,** a Nigerian crude, is calculated by applying the market differential of Brass River to the current Dated value. The prevailing market differential is also published separately.

The value of **Erha**, a Nigerian crude, is calculated by applying the market differential of Erha to the current Dated value. The prevailing market differential is also published separately.

The value of **Escravos**, a Nigerian crude, is calculated by applying the market differential of Escravos to the Dated value. The prevailing market differential is also published separately.

The value of **Forcados,** a Nigerian crude, is calculated by applying the market differential of Forcados to the current Dated value. The prevailing market differential is also published separately.

The value of **Qua Iboe**, a Nigerian crude, is calculated by applying the market differential of Qua Iboe to the current Dated value. The prevailing market differential is also published separately.

The value of **Cabinda**, an Angolan crude, is calculated by applying the market differential of Cabinda to the current Dated value. The prevailing market differential is also published separately.

The value of **Dalia**, an Angolan crude, is calculated by applying the market differential of Dalia to the current Dated value. The prevailing market differential is also published separately.

The value of **Girassol**, an Angolan crude, is calculated by applying the market differential of Girassol to the current Dated value. The prevailing market differential is also published separately.

The value of **Hungo**, an Angolan crude, is calculated by applying the market differential of Hungo to the current Dated value. The prevailing market differential is also published separately.

The value of **Kissanje**, an Angolan crude, is calculated by applying the market differential of Kissanje to the current Dated value. The prevailing market differential is also published separately.

The value of **Nemba**, an Angolan crude, is calculated by applying the market differential of Nemba to the current Dated value. The prevailing market differential is also published separately.

The value of **Zafiro**, a crude from Equatorial Guinea, is calculated by applying the market differential of Zafiro to the current Dated value. The prevailing market differential is also published separately.

Nigerian official formula prices

Argus also publishes official formula prices for crude from Nigeria. These are expressed as differentials to Dated for a given loading month and are set by Nigeria's national oil company NNPC.

West Africa assessments

Grade	typical °API	typical Sulphur %	Basis/Location	Timing	Cargo size
Agbami	47.2	0.05	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Amenam	40.8	0.93	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Bonga	29.11	0.292	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Bonny Light	34.5	0.14	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Brass River	36.5	0.13	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Erha	33.7	0.1798	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Escravos	34	0.15	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Forcados	30	0.15	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Qua Iboe	36.6	0.13	fob Nigeria	Loading 20-45 days ahead	950,000 bl
Cabinda	32.5	0.13	fob Angola	Loading 25-60 days ahead	950,000 bl
Dalia	23.7	0.49	fob Angola	Loading 25-60 days ahead	950,000 bl
Girassol	31	0.33	fob Angola	Loading 25-60 days ahead	950,000 bl
Hungo	27.4	0.65	fob Angola	Loading 25-60 days ahead	950,000 bl
Kissanje	30.7	0.36	fob Angola	Loading 25-60 days ahead	950,000 bl
Nemba	38.7	0.19	fob Angola	Loading 25-60 days ahead	950,000 bl
Zafiro	29.5	0.26	fob offshore Equatorial Guinea	Loading 25-60 days ahead	950,000 bl

Mideast Gulf (Argus Crude page 10)

The Dubai price is a leading benchmark for crude pricing. It is the benchmark for most of the sour crude exported from the Gulf to the east of Suez markets. Middle East crude oil sold to the eastern markets is traditionally valued against the price of Dubai or an average of the prices of Dubai and Oman. This is because Dubai is one of the few Middle Eastern crudes to be sold without extensive destination clauses and is available to a freely traded open spot market. Dubai's production, and therefore its market liquidity, has been in decline for many years. Few full cargoes of Dubai crude are now traded on the open spot market which means price discovery of the crude needs to reflect other transparent and liquid market indicators. Argus Dubai prices are identified through a swaps and spreads methodology.

Mideast Gulf assessments

Dubai

Argus assesses the price of Dubai in the same way that the market assesses the value of Dubai. Companies that trade the Dubai market convert their Dubai price exposure into a Brent price exposure. They do this because Brent price exposure is more easy to manage. The underlying traded volumes of Dubai swaps and the associated Ice Brent contract provide a more reliable and transparent basis for assessing the price of Dubai than any other methodological approach.

Argus begins its assessment of the Dubai price by reporting the active market in Dubai swaps based in Singapore. Dubai swaps are traded as an exchange of futures for swaps (EFS). Argus identifies and reports the prevailing EFS price, expressed as a differential to the Ice Brent price. This EFS value is subtracted from the prevailing price of Brent on the Ice at 4:30pm Singapore time to establish a fixed price for Dubai swaps.

Argus identifies the EFS value for the first three months forward. Applying these differentials to the first three months of the Ice Brent price provides Argus with absolute values for the first three months of the Dubai swaps market.

Dubai crude that is traded today is not loaded or priced for two months, so the swap price is the market's value of Dubai in three months time. This third-month forward price is then used to derive the physical Dubai price.

To derive the physical Dubai price, Argus assesses the Dubai intermonth spreads. There is an active intermonth Dubai spread market based in Singapore and London. Identifying the spread value between the third and the second month and also the second and the first month allows Argus to calculate the value of first-month Dubai.

In the event that the first to second month spread is so illiquid that a price cannot be established, Argus will use other market information, such as price indications for physical Dubai. These indications would normally be for south Asian destinations and expressed as a premium to the anticipated published Dubai price. Argus will make

an intelligent assessment based on such market information as is available to establish a value for first-month Dubai.

Argus can verify the market perception of the value of Dubai by analysing other key market differentials such as the Brent-Dubai spread, forward Brent prices and the market for exchange for physical (EFP) contracts in Brent.

Argus does not use partial Dubai to set its Dubai price assessments. Oman substitutionality into Dubai is not relevant in a swaps and spreads approach to price discovery.

The following table provides an example of the Argus assessment process for Dubai forward months:

Dubai forward month calculator			
Ice Brent month 1	Dec		87.34
Dubai EFS month 1	Dec	-	3.95
Dubai swap month 2*	Dec	=	83.39
Dubai forward month 3*	Feb	=	83.39
Dubai intermonth	Jan/Feb	+	-1.45
Dubai forward month 2	Jan	=	81.94
Dubai intermonth	Dec/Jan	+	-0.95
Dubai first month	Dec	=	80.99
*Dubai swap month 2 = Dubai forward month 3			

Oman

Argus assesses the price of Oman in the same way that most of the market assesses the value of Oman, by comparing the value of Oman with Dubai. Since the Oman government began setting the OSP for Oman crude in line with the monthly average of Oman futures traded on the Dubai Mercantile Exchange (DME) the over-the-counter spot trade of Oman has been priced in a variety of ways. Argus uses market premiums for full cargoes of spot Oman on a Dubai or a MOG basis to calculate its physical Oman price assessment.

For example: In the first half of October, Argus will assess front-month Oman as follows: December Oman equals the anticipated price of Dubai physical cargoes in December plus the market premium or discount of Oman.

Argus uses the openly traded swaps and spreads in the Dubai market to assess the price of Dubai. As a result, Argus does not have to use Oman substitutionality into Dubai.

The following table provides examples of the inputs Argus uses to calculate Oman forward months:

Oman forward month calculator					
	MOG formula	Dubai-Oman spread	Diff to Dubai swaps	Dubai swaps outright	Oman forward midpoint
Dec	+0.07	-2.47	-2.40	83.39	80.99
Jan	+0.07	-0.07	+0.00	84.64	84.64
Feb	+0.07	-0.07	+0.00	85.61	85.61

Murban and Lower Zakum

Argus assesses the price of Murban and Lower Zakum in the same way that most of the market assesses the values of Murban and Lower Zakum, by comparing the values of Murban and Lower Zakum with Dubai.

Argus assesses the prices of Murban and Lower Zakum using the price of Dubai modified by the market's differences between Dubai and the Murban and Lower Zakum official prices plus the prevailing premium (or discount) for Murban and Lower Zakum as currently traded.

In more detail, Argus will assess front-month Murban and Lower Zakum as follows: Second-month Dubai swap prices plus the difference between last month's OSP and last month's average Dubai plus the Argus assessment of the spot premium (or discount) for Murban and Lower Zakum versus the OSP.

For the last three days in any month, Argus will not use the difference between last month's OSP and last month's average Dubai but will substitute the difference between a forecast for the next OSP and current second-month Dubai swaps.

For example: October Murban equals October Dubai swaps plus expected OSP adjustment (July OSP less July Dubai average) plus the market premium or discount of the grade.

These assessments reflect cargoes loading two months from the date of publication.

Qatar Land and Qatar Marine

Argus assesses the price of Qatar Land and Qatar Marine in the same way that most of the market assesses the values of Qatar Land and Qatar Marine, by comparing the values of Qatar Land and Qatar Marine with Dubai.

Argus assesses the prices of Qatar Land and Qatar Marine using the price of Dubai modified by the market's differences between Dubai and the Qatar Land and Qatar Marine official prices plus the prevailing premium (or discount) for Qatar Land and Qatar Marine as currently traded.

In more detail, Argus will assess front-month Qatar Land and Qatar Marine as follows: Second-month Dubai swap prices plus the difference between last month's OSP and last month's average Dubai plus the Argus assessment of the spot premium (or discount) for Qatar Land and Qatar Marine versus the OSP.

For example: October Qatar Land equals October Dubai swaps plus expected OSP adjustment (July OSP less July Dubai average) plus market differential.

These assessments reflect cargoes loading two months from the date of publication.

Al-Shaheen

The **Al-Shaheen** assessment is the price of Al-Shaheen, a crude from Qatar. The value of Al-Shaheen is calculated by applying the market

differential of Al-Shaheen fob Qatar to Dubai swaps for the month of loading. The prevailing market differential is also published separately.

This assessment reflects cargoes loading two months from the date of publication.

Banoco Arab Medium

Argus assesses the price of Banoco Arab Medium in the same way that most of the market assesses the value of Banoco Arab Medium, by comparing the value of Banoco Arab Medium with the average of Dubai and Oman.

Argus assesses the price of Banoco Arab Medium using the average price of Dubai and Oman modified by the market's differences between the average of Dubai and Oman with the anticipated Banoco Arab Medium official price (based on the previous OSP set by Saudi Aramco for Arab Medium) plus the prevailing premium (or discount) for Banoco Arab Medium as currently traded.

In more detail, Argus will assess front-month Banoco Arab Medium as follows: The average of front-month Dubai swaps plus the difference between the Dubai Oman average with the most recent Saudi Aramco OSP for Arab Medium plus the Argus assessment of the spot premium (or discount) for Banoco Arab Medium versus the Saudi OSP for Arab Medium.

For example: October Banoco Arab Medium equals the average of October Dubai swaps and DME October daily Oman settlement plus the differential to Oman-Dubai set in the latest Saudi Arab Medium official formula price, plus the market differential for the grade. This assessment reflects cargoes loading two months from the date of publication.

Basrah Light

Argus assesses the price of Iraqi Basrah Light in the same way that most of the market assesses the value of Basrah Light, by comparing the value of Basrah Light with the average of Dubai and Oman.

Argus assesses the price of Basrah Light using the average values of Dubai swaps and Oman swaps, modified by the market's differences between the average of Dubai and Oman with the market participants' assessments of what the relevant Basrah Light official formula price will be, plus the prevailing spot market premium (or discount) for Basrah Light as currently traded on the spot market.

In more detail, Argus will assess front-month Basrah Light as follows:

The average of Dubai swaps and daily settlement for third month DME Oman crude futures (as this would reflect the Oman swaps value), plus the difference between the Dubai Oman average with the anticipated Somo official formula price, plus the *Argus* assessment of the spot premium (or discount) for Basrah Light versus the Somo official formula price.

For example: In July, the September Basrah Light assessment will equal to the average of September Dubai swaps and the daily DME Oman settlement for November contract (as this reflects September Oman swaps value), plus the anticipated differential to Oman-Dubai for the September Somo Basrah Light official formula price, plus the market differential for the grade. This assessment reflects cargoes loading two months from the date of publication.

Qatari DFC

The DFC (Deodorized Field Condensate) is the price of DFC, a condensate from Qatar. The value of DFC is calculated by applying the market differential of DFC fob Qatar to Dubai swaps for the month of loading. The prevailing market differential is also published separately.

For example: In July, the September DFC equals September Dubai swaps, plus the spot market differential for September-loading DFC cargoes

This assessment reflects cargoes loading two months from the date of publication.

Dubai forward

Argus assesses physical Dubai four months forward including the front month. Front-month physical Dubai is for cargoes loading two months from date of publication. For example, on 15 August, the front month is October. The forward months assessed are November, December and January. On 1 September, the front month will be November with forward assessments for December, January and February.

Argus assesses the prices of Middle East crude at 4:30pm Singapore time. *Argus* assessments of Middle East crude reflect cargo volumes of 400,000 bl for Dubai and 500,000 bl for other grades.

Argus assesses physical Oman three months forward. For example, on 15 August, *Argus* will assess October, November and December Oman.

The rollover of Middle East crude assessments to the next forward month will take place on the first calendar day of the month unless it falls on a weekend or holiday, when it will shift to the first business day of the month.

Mideast Gulf assessments

Grade	Typical °API	Typical sulphur %	Basis/Location	Timing	Cargo size
Dubai	31	2.04	fob Dubai	Month of loading	400,000 bl
Oman	33.3	1.06	fob Oman	Month of loading	500,000 bl
Murban	40.4	0.79	fob UAE	Month of loading	500,000 bl
Lower Zakum	39.2	1.10	fob UAE	Month of loading	500,000 bl
Qatar Land	41.1	1.22	fob Qatar	Month of loading	500,000 bl
Qatar Marine	36.2	1.60	fob Qatar	Month of loading	500,000 bl
Al-Shaheen	30.3	1.9	fob Qatar	Month of loading	600,000 bl
Banoco A M	31.8	2.45	fob Bahrain	Month of loading	500,000 bl
Basrah Light	30	2.92	fob Iraq	Month of loading	2mn bl
Qatari DFC	55	0.74	fob Qatar	Month of loading	500,000 bl

Argus assesses the bid/ask range on Dubai EFS at 4:30pm Singapore time for three calendar months. For example, on 15 August, *Argus* will assess the October, November and December Dubai EFS.

The rollover of Dubai swaps to the next forward month will take place on the first calendar day of the month or, in case of weekend or holiday, on the first business day of the month.

Asia-Pacific (Argus Crude page 11)

Argus assesses the price for a variety of Asia-Pacific crude grades. Argus assessments of Asia-Pacific crudes consist of a fixed-price or formula assessment and a differential assessment. All of these price assessments are made with a cut off of 4:30pm Singapore time, with the exception of those grades assessed on a North Sea Dated basis.

For those grades assessed relative to North Sea Dated, the differentials are assessed with a cut off of 4.30pm Singapore time, while the underlying North Sea Dated price is assessed at 4.30pm London time. The methodology behind the Dated assessment can be found in the North Sea section and on www.argusmedia.com.

Asia-Pacific assessments

Indonesia

Argus publishes assessments for Indonesian grades based on spot deals and market information for cargoes loading 15-45 days from the publication date.

The final price of **Minas** is assessed by determining the Minas spread to Ice Brent futures or to North Sea Dated. In addition to this final price, Argus also shows the current market premium/discount for Minas to the Indonesian Crude Price (ICP). The Minas base price is the price left when this market premium/discount is removed from the final Minas price.

The **Duri** assessment is based on an assessment of the spread between the grade and Minas. In the absence of specific market discussion, Argus will take into account the spread between the Minas and Duri ICP and activity on grades of similar quality.

The **Cinta** assessment is based on an assessment of the spread between the grade and Minas. In the absence of specific market discussion, Argus will take into account the spread between the Minas and Cinta ICP and activity on grades of similar quality.

The **Widuri** assessment is based on an assessment of the spread between the grade and Minas. In the absence of specific market discussion, Argus will take into account the spread between the Minas and Widuri ICP and activity on grades of similar quality.

The **Senipah** assessment is based on an assessment of the spread between the grade and Minas. In the absence of specific market discussion, Argus will take into account the spread between the Minas and Senipah ICP and activity on grades of similar quality.

The **Attaka** assessment is based on an assessment of the spread between the grade and Minas. In the absence of specific market discussion, Argus will take into account the spread between the Minas and Attaka ICP and activity on grades of similar quality.

The **Ardjuna** assessment is based on an assessment of the spread between the grade and Minas. In the absence of specific market discussion, Argus will take into account the spread between the Minas and Ardjuna ICP and activity on grades of similar quality.

The **Belida** assessment is based on an assessment of the spread between the grade and Minas. In the absence of specific market discussion, Argus will take into account the spread between the Minas and Belida ICP and activity on grades of similar quality.

Vietnam

Argus publishes assessments for Vietnamese grades based on spot deals and market information for cargoes loading 15-45 days from the publication date.

The **Bach Ho** assessment is calculated by applying the grade's differential relative to North Sea Dated to the same day's North Sea Dated value. The Bach Ho spot market premium/discount is also published separately. The market premium/discount is assessed with a cut off of 4:30pm Singapore time. In the absence of specific market discussion, Argus may look at other Vietnamese grades of similar quality, to assess the Bach Ho spot market premium/discount.

The **Sutu Den** assessment is calculated by applying the grade's differential relative to North Sea Dated to the same day's North Sea Dated value. The Sutu Den spot market premium/discount is also published separately. The market premium/discount is assessed with a cut off of 4:30pm Singapore time. In the absence of specific market discussion, Argus may look at other Vietnamese grades of similar quality, to assess the Sutu Den spot market premium/discount.

Malaysia

Argus publishes assessments for Malaysian grades based on spot deals and market information for cargoes loading 30-60 days from the publication date.

The **Tapis** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (*see below for the relevant methodology*).

The **Kikeh** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holi-

day, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

The **Labuan** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (*see below for the relevant methodology*).

Australia and PNG

Argus publishes assessments for Australian and PNG grades based on spot deals and market information for cargoes loading 30-60 days from the publication date.

PNG's **Kutubu Light** assessment is calculated by applying the grade's differential relative to North Sea Dated to the same day's North Sea Dated value. The differential is based on a market consensus, assessed with a cut off of 4:30pm Singapore time, and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

The **Cossack** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology). In the absence of specific market discussion, Argus will also take into account the spread between the Tapis APPI-linked Cossack price and North Sea Dated.

The **North West Shelf** condensate assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

The **Enfield** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

The **Stybarrow** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

The **Vincent** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

The **Pyrenees** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

The **Van Gogh** assessment is calculated by applying the grade's differential relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time. On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see below for the relevant methodology).

Substitute Dated

Substitute Dated replaces North Sea Dated as the base price for Cossack, Northwest Shelf condensate, Stybarrow, Enfield, Vincent, Nile Blend and Dar Blend on the few days each year when the Asian crude oil markets are operating, but a public holiday in the UK means that London will not produce a North Sea Dated price.

Substitute Dated is calculated at 4.30pm Singapore time. Substitute Dated comprises the Ice Brent 4.30pm Singapore one-minute marker plus or minus a differential representing the difference between the Brent futures market and the physical North Sea market.

This differential is calculated in the following manner: Argus takes the most recently available North Sea Dated price assessed in London, then it subtracts the London Ice Brent one-minute marker from that same day.

For example: Dated on 24 December was $72/bl and the Ice Brent 4.30pm London one-minute marker was $70/bl – a difference of $2/bl. To calculate Substitute Dated on 26 December, when Singapore is working but London is not, Argus will add this $2/bl difference to the Ice Brent 4.30pm Singapore one-minute marker ($69/bl) to give a Substitute Dated price of $71/bl.

The market differentials for Northwest Shelf condensate, Stybarrow, Enfield, Nile Blend and Dar Blend will then be added to this Substitute Dated price in line with their respective methodologies.

Sudan

Argus assessments of Sudanese crudes consist of a market differential to North Sea Dated and an outright price calculated by applying the differential to North Sea Dated.

Argus will publish assessments for Sudanese grades based on spot deals and market information for 600,000-1mn bl cargoes loading 15-45 days from the publication date. The cut off time for Sudanese assessments is 4:30pm Singapore time.

The **Nile Blend** assessment is calculated by applying the differential of Nile Blend relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time.

On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see above for the relevant methodology).

The **Dar Blend** assessment is calculated by applying the differential of Dar Blend relative to North Sea Dated based on a market consensus to the same day's North Sea Dated value. The differential is assessed with a cut off of 4:30pm Singapore time and applied to North Sea Dated, which becomes available after 4:30pm London time.

On days when North Sea Dated is unavailable due to a UK public holiday, Argus will use a substitute North Sea Dated price (see above for the relevant methodology).

ESPO Blend

The **ESPO Blend** assessment is the price of crude from the East Siberia-Pacific Ocean (ESPO) pipeline, loading at the port of Kozmino in the Russian Far East. The outright price of ESPO Blend is calculated by applying the daily average market differential for cargoes of ESPO Blend fob Kozmino to the relevant Dubai swaps assessment.

Trading begins when the first producer tenders to sell cargoes and ends when all of the cargoes in that loading programme have been sold by the primary sellers. Subsequent transactions will not be taken into account in calculating the average market differential. ESPO Blend trading begins 30–75 days before cargo loading dates. For example, cargoes loading from mid-November to mid-December could trade from early September until early October, although discussion usually begins after loading schedules are issued and tenders awarded in late September.

Argus will roll over the Dubai basis month when the bulk of deals done on the day are done for the first time on that basis. Any trade after this rollover that is based on a different Dubai basis month will then be converted to its equivalent value against the current month by using published Dubai inter-month spreads applicable on the day the deal was done.

The Argus assessment of ESPO Blend reflects the market price of 700,000 bl cargoes loading 30-75 days ahead of the publication date.

The cut-off time for ESPO Blend deals to be taken into account for the day's assessment will be 4:30pm Singapore time. Any deals completed after this pricing timestamp will be considered on the next day of publication of Argus Crude. Argus will also exclude from the day's assessment any deals for which confirmation is not available by 8:00pm Singapore time, and will consider them, once confirmed, in the next day's assessment, together with any fresh deals, using a simple arithmetic average. In the event that confirmation is still unavailable by 8:00pm Singapore time on the day after the deal was concluded, Argus will consider confirmed deals two publication days after the deal was concluded, provided there are no newer deals in that period, including the day when the deal was done. Any newer confirmed deals will supersede two-day-old deals. Argus will disregard any information on deals three publication days old or older. On days when Argus moves the assessment time for Dubai crude forward to 12:30pm Singapore time because of an upcoming holiday, it will also use a cut-off time of 12:30pm Singapore time for any ESPO Blend deals. Confirmation on these days should be available before 4:00pm Singapore time for Argus to consider these deals for that day's assessment. Otherwise, they will be considered in the next day of publication as stated above.

Sakhalin Island

Argus assessments of crudes from Sakhalin Island in Russia consist of a market differential to Dubai swaps for the month of loading and an outright price calculated by applying the differential to Dubai swaps for the month of loading. Argus will publish assessments for Sakhalin grades based on spot deals and market information for 700,000 bl cargoes loading two months ahead of the publication date. The cut off time for Sakhalin Island assessments is 4:30pm Singapore time.

Sakhalin Island assessments

The **Sokol** assessment is the price of Sokol, a crude from Sakhalin Island in Russia. The value of Sokol is calculated by applying the market differential of Sokol cif northeast Asia to Dubai swaps for the month of loading. The prevailing market differential is also published separately.

The **Vityaz** assessment is the price of Vityaz, a crude from Sakhalin Island in Russia. The value of Vityaz is calculated by applying the market differential of Vityaz cif Yosu to Dubai swaps for the month of loading. The prevailing market differential is also published separately.

The cut off time for the Sakhalin Island assessments is 4:30pm Singapore time.

The **BTC Blend cif basis Singapore** assessment is calculated by adding a freight component to the BTC fob Ceyhan assessment. The

freight cost is for 135,000t vessels and is assessed daily based on spot Med/Black Sea–East freight rates from the Argus Freight report.

Asia-Pacific, Sudan, ESPO Blend, Sakhalin Island assessments					
Grade	Typical °API	Typical sulphur %	Basis/ Location	Timing	Cargo size
Minas	35	0.08	fob Indonesia	Loading 15-45 days ahead	100,000 - 200,000 bl
Duri	21.5	0.20	fob Indonesia	Loading 15-45 days ahead	100,000 - 200,000 bl
Cinta	32.7	0.12	fob Indonesia	Loading 15-45 days ahead	100,000 - 200,000 bl
Widuri	33.3	0.07	fob Indonesia	Loading 15-45 days ahead	100,000 - 200,000 bl
Senipah	51	0.03	fob Indonesia	Loading 15-45 days ahead	250,000 bl
Attaka	43	0.09	fob Indonesia	Loading 15-45 days ahead	100,000 - 200,000 bl
Ardjuna	37	0.09	fob Indonesia	Loading 15-45 days ahead	100,000 - 200,000 bl
Belida	45	0.02	fob Indonesia	Loading 15-45 days ahead	100,000 - 200,000 bl
Bach Ho	39	0.04	fob Vietnam	Loading 15-45 days ahead	450,000 - 600,000 bl
Sutu Den	35.8	0.051	fob Vietnam	Loading 15-45 days ahead	450,000 - 600,000 bl
Tapis	46	0.02	fob Malaysia	Loading 30-60 days ahead	450,000 - 600,000 bl
Kikeh	36.74	0.06	fob Malaysia	Loading 30-60 days ahead	600,000 bl
Labuan	29.92	0.028	fob Malaysia	Loading 30-60 days ahead	300,000 - 600,000 bl
Kutubu Light	45	0.04	fob Papua New Guinea	Loading 30-60 days ahead	500,000 - 650,000 bl
Cossack	48	0.04	fob Australia	Loading 30-60 days ahead	500,000 - 650,000 bl
NW Shelf	60	0.01	fob Australia	Loading 30-60 days ahead	500,000 - 650,000 bl
Enfield	22	0.12	fob Australia	Loading 30-60 days ahead	500,000 - 650,000 bl
Stybarrow	22.7	0.117	fob Australia	Loading 30-60 days ahead	500,000 - 650,000 bl
Vincent	18.5	0.55	fob Australia	Loading 30-60 days ahead	500,000 - 650,000 bl
Pyrenees	19	0.21	fob Australia	Loading 30-60 days ahead	400,000 - 450,000 bl
Van Gogh	17	0.37	fob Australia	Loading 30-60 days ahead	500,000 - 650,000 bl
Nile Blend	32.76	0.045	fob Bashayer, Sudan	Loading 15-45 days ahead	600,000 - 1mn bl
Dar Blend	26.4	0.116	fob Bashayer, Sudan	Loading 15-45 days ahead	600,000 - 1mn bl
ESPO Blend	35.72	0.49	fob Kozmino	Loading 30-75 days ahead	700,000 bl
Sokol	37.10	0.27	cif northeast Asia	Month of loading	700,000 bl
Vityaz	41.80	0.16	cif Yosu	Month of loading	700,000 bl

Official formula prices (Argus Crude page 12)

Argus publishes official formula prices for crude from Saudi Arabia, Iran, Yemen, Kuwait, Iraq and Dubai. These are expressed as differentials to various benchmarks for a given loading month and are set by national oil companies.

Official selling prices (Argus Crude page 12)

Argus publishes official selling prices for crude from Abu Dhabi, Qatar, Oman, Indonesia, Malaysia and Brunei. These are expressed as outright prices for a given loading month and are set by national oil companies.

Reference prices (Argus Crude page 12)

Argus publishes the Opec Reference Basket monthly average price and also the Japanese Crude Cocktail import basket price.

Americas (*Argus Crude* pages 13-19)

Americas assessments

Prices for the following crude grades are listed in *Argus Crude*, along with daily market commentary. Coverage includes US Gulf coast and midcontinent, US west coast, Canada, and Latin America. A complete methodology for each of these crude prices can be found in the methodology document for *Argus Americas Crude* which can be located here.

West Texas Intermediate (WTI)

Grade	API Gravity	% Sulphur	Basis	Low/High Minimum Volume	VWA Aggregate Volume Minimum
WTI Cash Cushing	39.0	0.40	Cushing, OK	1,000 b/d	1,000 b/d
WTI CMA	39.0	0.40	Cushing, OK	1,000 b/d	1,000 b/d
WTI Midland	39.0	0.40	Midland, TX	1,000 b/d	1,000 b/d
WTI P-Plus	39.0	0.40	Cushing, OK	500 b/d	1,000 b/d

US Gulf Coast

Grade	API Gravity	% Sulphur	Basis	Low/High Minimum Volume	VWA Aggregate Volume Minimum
Bonito	33.7	1.02	fob St James, LA	500 b/d	1,000 b/d
Eugene Island	33.1	1.22	fob St. James, LA	500 b/d	1,000 b/d
HLS	32.0	0.42	fob Empire, LA	1,000 b/d	1,000 b/d
LLS (Month One)	37.0	0.38	fob Capline St. James LA	1,000 b/d	1,000 b/d
LLS (Month Two)	37.0	0.38	fob Capline St. James LA	500 b/d	1,000 b/d
Mars (Month One)	28.7	1.8	fob Clovelly, LA	1,000 b/d	1,000 b/d
Mars (Month Two)	28.7	1.8	fob Clovelly, LA	500 b/d	1,000 b/d
Poseidon	31	1.7	fob Houma, LA	500 b/d	1,000 b/d
Southern Green Canyon	28.7	2.38	fob Nederland, TX or Texas City, TX	500 b/d	1,000 b/d
Thunder Horse	32.7	0.62	fob Clovelly, LA	1,000 b/d	1,000 b/d

US Midcontinent

Grade	API Gravity	% Sulphur	Basis	Low/High Minimum Volume	VWA Aggregate Volume Minimum
WTI CMA	39.0	0.40	Cushing, OK	1,000 b/d	1,000 b/d
WTI Midland	39.0	0.40	Midland, TX	1,000 b/d	1,000 b/d
WTI P-Plus	39.0	0.40	Cushing, OK	500 b/d	1,000 b/d
WTS (Month One)	33.5	1.90	Midland, TX	1,000 b/d	1,000 b/d
WTS (Month Two)	33.5	1.90	Midland, TX	500 b/d	1,000 b/d
Bakken	40-42	0.17-0.20	Clearbrook, MN	500 b/d	
Western Canadian Select (WCS)	20-21	3.4-3.7	Cushing, OK	500 b/d	

US West Coast

Grade	API Gravity	% Sulphur	Basis	Low/High Minimum Volume
San Joaquin Light Blend	28.5	1.10	Belridge Station, CA	1,000 b/d
Line 63	28.5	1.10	Hynes Station, CA	1,000 b/d
Midway Sunset	13.0	1.20	Station 36, CA	1,000 b/d

Crudes assessed according to volume-weighted average method:

Grade	Density (kg/m3)	API Gravity	% Sulphur	Pricing Basis	VWA Aggregate Volume Minimum	Low/High Minimum Volume
Syncrude (SYN)	860	31-33	0.1-0.2	Pembina AOSP at Edmonton	1,000 b/d; 159m3	500 b/d; 80m3
Western Canadian Select (WCS)	925	20-21	3.4-3.7	Husky at Hardisty	1,000 b/d; 159m3	500 b/d; 80m3

US Gulf Coast

Grade	API Gravity	% Sulphur	Basis	Timing	Minimum Volume
Basrah Light	30.0	2.92	cif US Gulf coast	10-60 Days Forward	500,000 bl
Escravos	34.0	0.15	cif US Gulf coast	10-60 Days Forward	500,000 bl
Forties	40.3	0.56	cif US Gulf coast	10-60 Days Forward	500,000 bl
Kissanje	29.8	0.38	cif US Gulf coast	10-60 Days Forward	500,000 bl
Nemba	38.7	0.19	cif US Gulf coast	10-60 Days Forward	500,000 bl
Qua Iboe	36.6	0.13	cif US Gulf coast	10-60 Days Forward	500,000 bl
Saharan Blend	46.0	0.10	cif US Gulf coast	10-60 Days Forward	500,000 bl

US West Coast

Grade	API Gravity	% Sulphur	Basis	Minimum Volume
ANS	32.3	0.89	cif US west coast	300,000 bl
Oriente	24.0	1.40	cif US west coast	360,000 bl

Canada

Grade	API Gravity	% Sulphur	Pricing Basis	Timing	Minimum Volume
Hibernia	35.0	0.45	fob Whiffen Head, Newf.	10-45 Days Forward	500,000 bl
Terra Nova	33.2	0.48	fob Whiffen Head, Newf.	10-45 Days Forward	500,000 bl

Canada

Grade	API Gravity	% Sulphur	Pricing Basis	Low/High Minimum Volume
Condensate	61-65	0.08-0.20	Enbridge CRW pool at Edmonton	500 b/d; 80m3
Mixed Sweet (MSW)	39-40	0.45	Enbridge at Edmonton	1,000 b/d; 159m3
Lloyd Blend (LLB)	20-21	3.47	Hardisty	500 b/d
Light Sour Blend (LSB)	38.0	0.88	Enbridge or Westspur at Cromer	500 b/d
Canadian CMA	39.0	0.40	Cushing, OK	

Latin America

Grade	API Gravity	% Sulphur	Basis	Timing	Minimum Volume
Cano Limon	29.2	0.50	fob Colombia	10-60 Days Forward	500,000 bl
Castilla Blend	18.8	1.97	fob Colombia	10-60 Days Forward	500,000 bl
Escalante	24.1	0.19	fob Argentina	10-60 Days Forward	500,000 bl
Isthmus Formula	33.6	1.30	fob Mexico	10-60 Days Forward	500,000 bl
Maya Formula	22.0	3.30	fob Mexico	10-60 Days Forward	500,000 bl
Napo	18.5	2.00	fob Ecuador	10-60 Days Forward	360,000 bl
Olmeca Formula	39.3	0.80	fob Mexico	10-60 Days Forward	500,000 bl
Oriente	24.0	1.40	fob Ecuador	10-60 Days Forward	360,000 bl
Vasconia	24.3	0.83	fob Colombia	10-60 Days Forward	500,000 bl

Argus Sour Crude Index (*ASCI*)

Argus publishes a daily price series that represents the value of US Gulf coast medium sour crude by including transactions from three separate crude streams: Mars, Poseidon and Southern Green Canyon. The Argus Sour Crude Index (*ASCI*) is a pricing tool that provides a broader index of US Gulf coast medium sour crude value for use in contracts. A full description of the methodology for the *ASCI* price is available by clicking here.

Updates

For the publication schedule check www.argusmedia.com.
The Argus Americas Crude methodology is constantly updated and revised. The latest available methodology (which may supersede the one you are reading) is available at www.argusmedia.com.

Argus intra-day North Sea forward physical crude assessments

On Ice front-month Brent futures expiry days, *Argus* publishes intra-day North Sea forward physical crude assessments for the corresponding expiring month at the following timestamps: 10:30,12:30,14:30,16:30,19:30 London time.

The methodology for identifying these price assessments is as follows:

Argus bases its front-month North Sea forward physical crude assessments on a volume-weighted average of outright North Sea forward trade in the minute leading up to each timestamp.

In the absence of outright trade, *Argus* will base its assessment on a formula comprising the second-month exchange of futures for physical (EFP) differential, the North Sea forward physical front-month to second-month (intermonth) differential and a representative second-month Ice Brent futures value. Outright North Sea forward physical bids and offers will be taken into account if they fall within a range derived from the bid-offer spread on the second-month EFP market, the bid-offer spread of the North Sea forward physical intermonth market, and a representative second-month Ice Brent futures value.

The North Sea forward physical assessments are assessed individually, as follows:

The front-month North Sea forward physical value is assessed using a volume-weighted average of trade taking place in the minute leading up to the timestamp and reported to *Argus* no more than 10 minutes after the timestamp.

The second-month Ice Brent futures value is assessed using trade in the minute leading up to the timestamp, or if there is no activity, the last trade before the timestamp.

For the EFP and North Sea forward physical intermonth values, *Argus* takes into account reported trade or indications leading up to the timestamp. If there is a period without reported trade or indications, *Argus* will base its assessments on activity in the preceding period.

These assessments, including the 16:30 London time assessment for North Sea Dated, are different and distinct from the assessments published in the Argus Crude report.

METHODOLOGY AND SPECIFICATIONS GUIDE

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ARGUS AMERICAS CRUDE

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LAST UPDATED: MAY 2013

The most up-to-date *Argus Americas Crude* methodology is available on www.argusmedia.com

Methodology overview

Methodology rationale

Argus strives to construct methodologies that reflect the way the market trades. Argus aims to produce price assessments which are reliable indicators of commodity market values, free from distortion and representative of spot market values. As a result, the specific currencies, volume units, locations and other particulars of an assessment are determined by industry consensus to facilitate seamless bilateral trade and Argus mirrors these industry conventions.

In the Americas crude markets, Argus typically reflects physical market prices across the entire trading day as a low and high of deals done and in some markets a volume-weighted average of deals done. In illiquid markets and time periods, Argus assesses the range within which crude could have traded by applying a strict process outlined later in this methodology. In some markets, Argus also produces cumulative transaction averages across a month and cumulative daily averages. An entire day price is a reliable indicator of physical market values as it incorporates the broadest possible pool of spot market liquidity and has acceptance from industry. Argus applies crude basis differential transactions to the WTI settlement price to arrive at fixed prices because the futures settlement price is a representative futures price reference. This approach has been endorsed by industry acceptance. Certain markets are referenced to Brent crude at a certain time of day, and details are located in the sections below. See also section "Definition of trading day."

In order to qualify to set the low or high of the day, deals must meet the minimum volume, delivery, timing, and specification requirements in our methodology, and the deals must be bona fide. With the exception of volume, the same requirements apply to volume-weighted averages.

Definition of trading day

Argus defines the trading day by determining at what times the market can be said to contain a fair number of willing buyers and sellers. Outside of these time boundaries, markets are typically too illiquid to produce representative price indications and deals. These boundaries can vary in different markets, and will be under continuous review to maintain the accuracy of the assessments. The trading day is defined as follows:

US Gulf coast pipeline	7:00am – 3:00pm CST
US midcontinent pipeline	7:00am – 3:00pm CST
Canadian pipeline	7:00am – 3:30pm MST
USGC waterborne	8:00am – 4:00pm CST
Canada waterborne	8:00am – 3:30pm CST
Latin America waterborne	8:00am – 4:00pm CST
US west coast pipeline	7:00am – 4:00pm PST
US west coast waterborne	7:00am – 4:00pm PST

For Canada, on days when the CME Nymex is closed but Canadian physical oil markets are open (eg US Thanksgiving, US Independence Day), Argus will not publish its Americas Crude Report (ACR), but it will gather Canadian deals and create volume-weighted indices and high/low market assessments for Canadian grades. These price assessments will be entered into the Argus price database as on any regular business day, and subscribers to Argus data will have access to the updated data as on any other business day. Only differential indices will be calculated on these days; outright prices will not be calculated because there will be no Nymex crude settlement to provide the fixed price component.

Argus will announce its publishing schedule in a calendar located at www.argusmedia.com. Argus may not assess prices on certain public holidays even when the exchanges are open, due to anticipated illiquidity in the cash spot markets.

Survey process

Argus price assessments are informed by information received from a wide cross section of market participants, including producers, consumers and intermediaries. Argus reporters engage with the industry by proactively polling participants for market data. Argus will contact and accept market data from all credible market sources including front and back office of market participants and brokers. Argus will also receive market data from electronic trading platforms and directly from the back offices of market participants. Argus will accept market data by telephone, instant messenger, email or other means.

Argus encourages all sources of market data to submit all market data to which they are a party that falls within the Argus stated methodological criteria for the relevant assessment. Argus encourages all sources of market data to submit transaction data from back office functions when and where possible.

Throughout all markets, Argus is constantly seeking to increase the number of companies willing to provide market data. Reporters are mentored and held accountable for expanding their pool of contacts. The number of entities providing market data can vary significantly from day to day based on market conditions. Should the number of entities providing market data repeatedly fall to a level that assessment quality may be affected, supervising editors will review the viability of the assessment.

For certain price assessments identified by local management, should more than 50pc of the market data upon which the assessment is based come from a single entity during any assessment period (defined as the minimum period covered, such as a day for a daily assessment), then the supervising editor will engage in an analysis of the market data with the primary reporter to ensure that the quality and integrity of the assessment has not been affected.

Argus has committed to deliver many of our final published prices to clients by a particular deadline each day. Because compiling and confirming transactions and other market data in advance of this deadline is a lengthy process, price assessment procedures must be concluded well before that deadline. As a result, for the Americas crude markets, Argus has instituted cut-off times for the submission of data by market participants. Argus will review all data received after the cut-off time and will make best efforts to include in the assessment process all verifiable transactions and market data received after the cut-off time but reserves the right to exclude any market data from the process if received after the cut-off time.

Cut-off times

US Gulf coast and midcontinent pipeline	3:00 pm CST
US West coast waterborne and pipeline	4:00 pm CST
Canadian pipeline	5:00 pm CST
Gulf coast and Canadian waterborne	4:00 pm CST
Latin America	4:00 pm CST

Market data usage

In each market, Argus uses the methodological approach deemed to be the most reliable and representative for that market. Argus will utilize various types of market data in its methodologies, to include:

1. Transactions
2. Bids and offers
3. Other market information, to include spread values between grades, locations, timings, and many other data.

In many markets, the relevant methodology will assign a relatively higher importance to transactions over bids and offers, and a relatively higher importance to bids and offers over other market information. Certain markets however will exist for which such a hierarchy would produce unreliable and non-representative price assessments, and so the methodology must assign a different relative importance in order to ensure the quality and integrity of the price assessment. And even in markets for which the hierarchy normally obtains, certain market situations will at times emerge for which the strict hierarchy would produce non-representative prices, requiring Argus to adapt in order to publish representative prices.

Verification of transaction data

Reporters carefully analyze all data submitted to the price assessment process. This data includes transactions, bids, offers, volumes, counterparties, specifications and any other information that contributes materially to the determination of price. This high level of care applies regardless of the methodology employed. Specific to transactions, bids, and offers, reporters seek to verify the price, the volume, the specifications, location basis, and counterparty. In some transactional average methodologies, reporters also examine the full array of transactions to match counterparties and arrive at a list of unique transactions.

Several tests are applied by reporters in all markets to transactional data to determine if it should be subjected to further scrutiny. If a transaction has been identified as failing such a test, it will receive further scrutiny. For certain price assessments identified by local management, Argus has established internal procedures that involve escalation of inquiry within the source's company and escalating review within Argus management. Should this process determine that a transaction should be excluded from the price assessment process, the supervising editor will initiate approval and, if necessary, documentation procedures.

Primary tests applied by reporters

- Transactions not transacted at arms-length, including deals between related parties or affiliates.
- Transaction prices that deviate significantly from the mean of all transactions submitted for that day.
- Transaction prices that fall outside of the generally observed lows and highs that operated throughout the trading day.
- Transactions that are suspected to be a leg of another transaction or in some way contingent on an unknown transaction.
- Single deal volumes that significantly exceed the typical transaction volume for that market.
- Transaction details that are identified by other market participants as being for any reason potentially anomalous.
- Transaction details that are reported by one counterparty differently than the other counterparty.
- Any transaction details that appear to the reporter to be illogical or to stray from the norms of trading behavior. This could include but is not limited to divergent specifications, unusual delivery location and counterparties not typically seen.
- Transactions that involve the same counterparties, the same price and delivery dates are checked to see that they are separate deals and not one deal duplicated in Argus records.

Secondary tests applied by editors for transactions identified for further scrutiny

Transaction tests

- The impact of linkage of the deal to possible other transactions such as contingent legs, exchanges, options, swaps, or other derivative instruments. This will include a review of transactions in markets that the reporter may not be covering.
- The nature of disagreement between counterparties on transactional details.
- The possibility that a deal is directly linked to an offsetting transaction that is not publicly known, for example a "wash trade" which has the purpose of influencing the published price.
- The impact of non-market factors on price or volume, including distressed delivery, credit issues, scheduling issues, demurrage, or containment.

Source tests

- The credibility of the explanation provided for the outlying nature of the transaction.
- The track record of the source submitting the data. Sources will be deemed more credible if they
  - Regularly provide transaction data with few errors.
  - Provide data by Argus' established deadline.
  - Quickly respond to queries from Argus reporters.
  - Have staff designated to respond to such queries.
- How close the information receipt is to the deadline for information, and the impact of that proximity on the validation process.

Assessment guidelines

When insufficient, inadequate, or no transaction information exists, or when a transaction based methodology will not produce representative prices, Argus reporters will make an assessment of market value by applying intelligent judgment based on a broad array of factual market information. Reporters must use a high degree of care in gathering and validating all market data used in determining price assessments, a degree of care equal to that applying to gathering and validating transactions. The information used to form an assessment could include deals done, bids, offers, tenders, spread trades, exchange trades, fundamental supply and demand information and other inputs.

The assessment process employing judgment is rigorous, replicable, and uses widely accepted valuation metrics. These valuation metrics mirror the process used by physical commodity traders to internally assess value prior to entering the market with a bid or offer. Applying these valuation metrics along with sound judgment significantly narrows the band within which a commodity can be assessed, and greatly increases the accuracy and consistency of the price series. The application of judgment is conducted jointly with the supervising editor, in order to be sure that guidelines below are being followed. Valuation metrics include the following:

Relative value transactions

Frequently transactions occur which instead of being an outright purchase or sale of a single commodity, are instead exchanges of commodities. Such transactions allow reporters to value less liquid markets against more liquid ones and establish a strong basis for the exercise of judgement.

- Exchange one commodity for a different commodity in the same market at a negotiated value.
- Exchange delivery dates for the same commodity at a negotiated value.
- Exchange a commodity in one location for the same commodity at another location at a negotiated value.

Bids and offers

If a sufficient number of bids and offers populate the market, then the highest bid and the lowest offer can be assumed to define the boundaries between which a deal could be transacted.

Comparative metrics

The relative values between compared commodities are readily discussed in the market and can be discovered through dialogue with market participants. These discussions are the precursor to negotiation and conclusion of transactions.

- Comparison to the same commodity in another market center.
- Comparison to a more actively traded but slightly different specification commodity in the same market center.
- Analysis of prices in forward markets for physically deliverable commodity that allow extrapolation of value into the prompt timing for the commodity assessed.
- Comparison to the commodity's primary feedstock or primary derived product(s).
- Comparison to trade in the same commodity but in a different modality (as in barge versus oceangoing vessel) or in a different total volume (as in full cargo load versus partial cargo load).

Throughout this methodology, Argus will explain, in more detail and on a market by market basis, the criteria and procedures that are used to make an assessment of market value by applying intelligent judgment. Extensive subsections will be labeled with the header "Assessment Guidelines."

Volume minimums and transaction data thresholds

In establishing each methodology, Argus will list specific minimum volume for each assessment. Because of the varying transportation infrastructure found in all commodity markets, Argus typically does not establish thresholds strictly on the basis of a count of transactions, as this could lead to unreliable and non-representative assessments. Instead, minimum volumes are typically established which may apply to each transaction accepted, to the aggregate of transactions, to transactions which set a low or high assessment or to other volumetrically relevant parameters.

For certain price assessments identified by local management, Argus will seek to establish minimum transaction data thresholds and when no such threshold can be established Argus will explain the reasons. These thresholds will often reflect the minimum volumes necessary to produce a transaction-based methodology, but may also establish minimum deal parameters for use by a methodology that is based primarily on judgment.

Should no transaction threshold exist, or should submitted data fall below this methodology's stated transaction data threshold for any reason, Argus will follow the procedures outlined elsewhere in this document regarding the exercise of judgment in the price assessment process.

Minimum transaction thresholds for key assessments

Commodity	Modality	Location	Minimum Transaction Thresholds: Low/high minimum volume	Minimum Transaction Thresholds: VWA aggregate minimum volume
WTI Formula Basis month 1	Pipeline	Cushing, OK	1,000 b/d	1,000 b/d
LLS month 1	Pipeline	St James, LA	1,000 b/d	1,000 b/d
Mars month 1	Pipeline	Clovelly, LA	1,000 b/d	1,000 b/d
WTS	Pipeline	Midland, TX	1,000 b/d	1,000 b/d
WTI Midland	Pipeline	Midland, TX	1,000 b/d	1,000 b/d
ASCI	Index	n/a	n/a	6,000 b/d
Poseidon	Pipeline	Houma, LA	500 b/d	1,000 b/d
SGC	Pipeline	Nederland/ Texas City, TX	500 b/d	1,000 b/d

Transparency and confidentiality

Argus values transparency in energy markets. As a result, we publish lists of deals in our reports that include price, basis, and volume information. The deal tables allow subscribers to cross check and verify the deals against the prices. Argus feels transparency and openness is vital to developing confidence in the price assessment process.

Argus asks for transaction counterparty names from contacts in order to confirm deals and to avoid double-counting in volume-weighted averages. But Argus does not publish counterparty names in the Americas crude markets. Many companies have existing confidentiality agreements with counterparties and can only reveal deals to the press if confidentiality is maintained. Maintaining confidentiality allows Argus to gather more information and create more robust assessments.

Basis differentials and absolute prices

In the Americas crude markets, differentials to futures benchmarks or to secondary benchmarks are the negotiated bids, offers, and transaction values. Argus fixed prices are derived by adding the assessed differentials to the benchmark price.

US pipeline differentials are applied to the WTI Formula Basis in order to derive fixed prices. The WTI Formula Basis is represented as a single outright price and is provided for two months forward. US west coast grade differentials are expressed against local posted prices. Waterborne Canadian grades Hibernia and Terra Nova are referenced against North Sea Dated. Certain Latin American grades and waterborne cargoes utilize ICE Brent as a price reference. Mexican crude prices are published as a single value, with equivalent differentials derived against front-month Nymex crude futures, for easy comparison against other grades assessed around the Americas. Detailed explanations of the use of postings, calendar month averages, and the WTI Formula Basis are covered in individual sections in this document.

Argus publishes various price types for each commodity. These typically include

Differential Low: The low differential to a reference price.
Differential High: The high differential to a reference price.
Differential Weighted Average: A value arrived at by multiplying each deal's volume by its differential price, summing the resulting value for all deals in a grade on a given day, and dividing that final sum by the total volume. Expressed as a differential to a reference price.
Differential Month-to-Date Weighted Average: An average of the daily differential weighted averages since the first day of the current trade month up to and including the date of assessment. Expressed as a differential to a reference price.
Low: The "fixed" or "outright" price. Reference price plus differential low.
High: The "fixed" or "outright" price. Reference price plus differential high.
Weighted Average: The weighted average "fixed" or "outright" price. Reference price plus differential weighted average.
Delta: The change between today's absolute price and that of the previous trading day.

Swaps and forwards markets

Argus publishes forward assessments for numerous markets. These include forward market contracts that can allow physical delivery and swaps contracts that swap a fixed price for the average of a floating published price. Argus looks at forward swaps to inform physical assessments but places primary emphasis on the physical markets.

Publications and price data

Argus crude prices for the Americas are published in the *Argus Americas Crude* report. These prices appear as a subset of the daily *Argus Crude* report which adds coverage of markets in Europe, Africa, the Mideast Gulf and Asia-Pacific. Other Argus publications also include some *Argus Americas Crude* pricing data. Among these publications are *Argus Latin Markets*, *Argus Global Markets*, *Argus Asphalt* and *Argus LatAm Energy*. The price data is available independent of the text-based report in electronic files that can feed into various databases. These price data are also supplied through various third-party data integrators. The Argus website also provides access to prices, reports and news with various web-based tools. All Argus prices are kept in a historical database and available for purchase. Contact your local Argus office for information.

Corrections to assessments

Argus will on occasion publish corrections to price assessments after the publication date. We will correct errors that arise from clerical

mistakes, calculation errors, or a misapplication of our stated methodology. Argus will not retroactively assess markets based on new information learned after the assessments are published. We make our best effort to assess markets based on the information we gather during the trading day assessed.

If transaction information is submitted in error, and the company submitting informs Argus of the error within 24 hours of the original submission, Argus will make best efforts to correct the price data. After 24 hours, Argus will review both the material effect that the correction will have on the price data and the amount of time that has elapsed from the date of the published price data before deciding whether to issue a correction. After 30 days, submitters are not expected to file corrections to submitted data.

Ethics and compliance

Argus operates according to the best practices in the publishing field, and maintains thorough compliance procedures throughout the firm. We want to be seen as a preferred provider by our subscribers, who are held to equally high standards, while at the same time maintaining our editorial integrity and independence. Argus has a strict ethics policy that applies to all staff. The policy can be found on our website at www.argusmedia.com. Included in this policy are restrictions against staff trading in any energy commodity or energy related stocks, and guidelines for accepting gifts. Argus also has strict policies regarding central archiving of email and instant messenger communication, maintenance and archiving of notes, and archiving of spreadsheets and deal lists used in the price assessment process. Argus publishes prices that report and reflect prevailing levels for open-market arm's length transactions (please see the Argus Global Compliance Policy for a detailed definition of arms length).

Consistency in the assessment process

Argus recognizes the need to have judgment consistently applied by reporters covering separate markets, and by reporters replacing existing reporters in the assessment process. In order to ensure this consistency, Argus has developed a program of training and oversight of reporters. This program includes:

1. A global price reporting manual describing among other things the guidelines for the exercise of judgment.
2. Cross-training of staff between markets to ensure proper holiday and sick leave backup. Editors that float between markets to monitor staff application of best practices.
3. Experienced editors overseeing reporting teams are involved in daily mentoring and assisting in the application of judgment for illiquid markets.
4. Editors are required to sign-off on all price assessments each day, thus ensuring the consistent application of judgment.

Review of methodology

The overriding objective of any methodology is to produce price assessments which are reliable indicators of commodity market values, free from distortion and representative of spot market values. As a result, Argus editors and reporters are regularly examining our methodologies and are in regular dialogue with the industry in order to ensure that the methodologies are representative of the physical market being assessed. This process is integral with reporting on a given market. In addition to this ongoing review of methodology, Argus conducts reviews of all of its methodologies and methodology documents on at least an annual basis.

Argus market report editors and management will periodically and as merited initiate reviews of market coverage based on a qualitative analysis that includes measurements of liquidity, visibility of market data, consistency of market data, quality of market data and industry usage of the assessments. Report editors will review:

- Appropriateness of the methodology of existing assessments
- Termination of existing assessments
- Initiation of new assessments

The report editor will initiate an informal process to examine viability. This process includes:

- Informal discussions with market participants
- Informal discussions with other stakeholders
- Internal review of market data

Should changes, terminations, or initiations be merited, the report editor will submit an internal proposal to management for review and approval. Should changes or terminations of existing assessments be approved, then formal procedures for external consultation are begun.

Changes to methodology

Formal proposals to change methodologies typically emerge out of the ongoing process of internal and external review of the methodologies. Formal procedures for external consultation regarding material changes to existing methodologies will be initiated with an announcement of the proposed change published in the relevant Argus report. This announcement will include:

- Details on the proposed change and the rationale
- Method for submitting comments with a deadline for submissions
- Notice that all formal comments will be published after the given consultation period unless submitter requests confidentiality

Argus will provide sufficient opportunity for stakeholders to analyze and comment on changes, but will not allow the time needed to follow these procedures to create a situation wherein unrepresentative or false prices are published, markets are disrupted, or market participants are put at unnecessary risk. Argus will engage with industry throughout this process in order to gain acceptance of proposed changes to methodology. Argus cannot however guarantee universal acceptance and will act

for the good order of the market and ensure the continued integrity of its price assessments as an overriding objective.

Following the consultation period, Argus management will commence an internal review and decide on the methodology change. This will be followed by an announcement of the decision in the relevant Argus report and include a date for implementation. In addition, publication of stakeholders' formal comments that are not subject to confidentiality and Argus' response to those comments will also take place.

These formal comments should be published in a manner described by management but must be available to all market participants and stakeholders.

Updates to methodology

The Argus Americas Crude methodology is constantly updated and revised. The latest available methodology (which may supersede the one you are reading) is available at www.argusmedia.com.

Americas Pipeline Markets

WTI-related markets

West Texas Intermediate (WTI)

Grade	API Gravity	% Sulphur	Basis	Low/High Minimum Volume	VWA Aggregate Volume Minimum
WTI Cash Cushing	39.0	0.40	Cushing, OK	1,000 b/d	1,000 b/d
WTI CMA	39.0	0.40	Cushing, OK	1,000 b/d	1,000 b/d
WTI Midland	39.0	0.40	Midland, TX	1,000 b/d	1,000 b/d
WTI P-Plus	39.0	0.40	Cushing, OK	500 b/d	1,000 b/d

WTI Cushing and WTI Formula Basis

The spot price for WTI at Cushing, Oklahoma is assessed four months forward. It reflects Nymex light sweet crude futures settlements at 1.30pm Central time. For the front-month assessment in the three days following expiration of Nymex futures, trades done for the Month-One/Month-Two Cash Roll throughout the day are averaged on a volume-weighted basis. The resulting Cash Roll average is then applied to that day's price for WTI Nymex prompt month settlement, in order to derive the first-month WTI Cushing value. If there are no cash roll trades on one of the three days following expiry, *Argus* will use an assessment of where the cash roll was valued by participants in the market that day. Assessments for cash WTI at Cushing roll to the next month on the fourth business day following expiration of the front-month Nymex light sweet crude futures contract (see sidebar).

For US pipeline assessments, outright prices are derived by adding differentials to Nymex settlement prices until their expiration. For the three days between futures expiration and pipeline scheduling, those differentials are added to the WTI Cushing spot assessment (see above).

In order to facilitate the use of *Argus* prices, *Argus* combines Nymex futures and WTI spot prices into a single pricing series called the "WTI Formula Basis". This series represents the Nymex settlement up to and including futures expiry, then automatically switches to represent the mean of the first month WTI Cushing spot assessment for the three business days which precede pipeline scheduling. Companies using *Argus* to price US pipeline crudes need only reference the WTI Formula Basis in their contracts when needing to reference the WTI component of another crude. For example, the "fixed", "outright" or "absolute" price for LLS prompt month minus the WTI Formula Basis prompt month equals the LLS prompt month differential.

Nymex expiration dates

Expiration dates for the Nymex light sweet crude futures contract are aligned with the scheduling deadline for shipments on US pipelines. For US pipelines, shipments must be scheduled no later than the 25th day of the preceding month. In the event that the 25th falls on a weekend or holiday, the pipeline scheduling deadline moves forward to the first business day before the 25th. Nymex looks at each month's pipeline scheduling deadline, and sets the expiration for front-month crude futures three business days prior to that. As an example, 25 January 2010 falls on a Monday. This will be the deadline for scheduling February pipeline shipments. Counting back 3 business days from 25 January shows that the February 2010 light sweet crude futures contract will expire on Wednesday 20 January. However in April 2010, the 25th day falls on a Sunday. This means pipeline scheduling for May shipments will occur on Friday 23 April. Counting back three business days from 23 April indicates that the May 2010 futures contract will expire on Tuesday 20 April 2010.

Nymex Calendar Month Averages

The US and Canadian markets use various Calendar Month Averages (CMA) of the light sweet crude futures settlement prices on Nymex as a reference for trading WTI and other grades.

US Markets

WTI at Cushing can trade at either a differential to a "Merc" Days average or a differential to a Calendar Days (also known as "Cal" Days or All Days) average. Both methods are based on the spread between the first and second, and between the first and third, Nymex light sweet crude futures contracts. This method is designed to arrive at a reference price that represents WTI on a calendar month basis instead of a trade month.

Merc Days: The most common CMA basis in the US is the Merc Days average, which is calculated using only days when the Nymex is open for business.

Calendar Days: The less common Calendar Days method extends the Nymex settlement prices from Friday, replicating it as the value for Saturday and Sunday. It then includes both work days and weekend days in the average. Market holidays carry over the value of the previous business day's settlement as well.

The *Argus* Diff to CMA assessment is a volume-weighted average of differentials traded against both the Merc Days and Calendar Days CMA bases, since the two methods typically yield numbers that differ only slightly from one another. *Argus* includes both in the single assessment to reflect the maximum amount of liquidity available, but keeps the policy under review should market conditions change.

Posted prices

Argus assesses WTI on a Postings-Plus basis, where the market trades a spot premium to the prompt WTI postings issued by various oil companies. *Argus* does not endorse one posting over any other.

Traders typically base P-Plus deals off the posting issued by Phillips 66, but on rare occasions may also use postings issued by other companies like Plains or Shell. *Argus* does not publish the WTI postings issued by any company, but the Phillips 66 price referenced by most traders can be found at this link:
http://www.phillips66.com/EN/products/business/crude_oil/bulletin/Pages/index.aspx. (as of 1 May 2013.)

US Gulf coast and midcontinent pipeline

US Gulf coast

Grade	API Gravity	% Sulphur	Basis	Low/ High Minimum Volume	VWA Agreggate Volume Minimum
Bonito	33.7	1.02	fob St. James, LA	500 b/d	1,000 b/d
Eugene Island	33.1	1.22	fob St. James, LA	500 b/d	1,000 b/d
HLS	32.0	0.42	fob Empire, LA	1,000 b/d	1,000 b/d
LLS (Month One)	37.0	0.38	fob Capline St. James LA	1,000 b/d	1,000 b/d
LLS (Month Two)	37.0	0.38	fob Capline St. James LA	500 b/d	1,000 b/d
Mars (Month One)	28.7	1.8	fob Clovelly, LA	1,000 b/d	1,000 b/d
Mars (Month Two)	28.7	1.8	fob Clovelly, LA	500 b/d	1,000 b/d
Poseidon	31	1.7	fob Houma, LA	500 b/d	1,000 b/d
Southern Green Canyon	28.7	2.38	fob Nederland, TX or Texas City, TX	500 b/d	1,000 b/d
Thunder Horse	32.7	0.62	fob Clovelly, LA	1,000 b/d	1,000 b/d

US midcontinent

Grade	API Gravity	% Sulphur	Basis	Low/ High Minimum Volume	VWA Agreggate Volume Minimum
WTI CMA	39.0	0.40	Cushing, OK	1,000 b/d	1,000 b/d
WTI Midland	39.0	0.40	Midland, TX	1,000 b/d	1,000 b/d
WTI P-Plus	39.0	0.40	Cushing, OK	500 b/d	1,000 b/d
WTS (Month One)	33.5	1.90	Midland, TX	1,000 b/d	1,000 b/d
WTS (Month Two)	33.5	1.90	Midland, TX	500 b/d	1,000 b/d
Bakken	40-42	0.17-0.20	Clearbrook, MN	500 b/d	
Western Canadian Select (WCS)	20-21	3.4-3.7	Cushing, OK	500 b/d	

Low and High Prices

Argus assesses the range of trade for each grade over the entire day, subject to certain volume minimums depending on the grade. For US Gulf coast crudes, WTI Midland and WTS, these numbers are displayed both as differentials to the WTI Formula Basis, and as fixed prices. In order to set the low or high of the daily range, a deal must meet a volume minimum established for each grade, typically either 500 or 1,000 b/d. If there is insufficient trade for a particular grade on any given day, *Argus* will assess the range in which trade could have occurred based on various market indications. Minimum volume thresholds by grade are listed in the tables above.

Argus assessments of the Bakken and WCS Cushing price ranges are based on the highest and lowest price achieved on any given trading day. To set the high or low for the range, a deal must reach a certain volume threshold, as shown in the table. For Bakken, prices are published as differentials to the Canadian CMA and as fixed prices. For WCS Cushing, prices are published as fixed prices and as differentials to both the Canadian CMA and the concurrent WTI contract. On a given day, trades against either or both bases will be used to determine a high and low range that is inclusive of all trades that day. On illiquid days, prices represent the low and high range within which WCS Cushing could have traded throughout the trading day.

Volume-Weighted Averages

For US Gulf coast and midcontinent WTI and WTS, *Argus* publishes volume-weighted averages of deals done through the entire trading day. These are published as a single differential to the WTI Formula Basis, and as a single fixed price. All bona fide deals reported to *Argus*, regardless of size, are factored into volume-weighted averages. However, *Argus* must have at least 1,000 b/d of total trade for a grade in order to calculate a volume-weighted average price. If a grade does not have a total of at least 1,000 b/d done on any given day as a differential to WTI, Argus will make an assessment of the volume-weighted price.

Differential Month-to-Date Weighted Average

Each day, in the US Gulf coast and midcontinent markets, *Argus* publishes an average of the prompt month volume-weighted average differentials for the trade month to date, including the day of publication. This value is rounded to two decimal places in the daily pricing table.

At the conclusion of each trade month, *Argus* publishes a table of average trade-month values, both on a differential and fixed-price basis for US pipeline crudes. Because industry crude contracts typically specify pricing to the fourth decimal place, *Argus* shows these final calculations at the end of the trade-month to the fifth decimal place, so that any issues with rounding will not impact contract buyers or sellers of the crude.

Stream Quality

US pipeline grades are created by blending the output from many different fields flowing into a particular pipeline system. Production volumes and quality from individual fields can change, as can transportation logistics into or out of pipeline systems. Such changes inevitably alter the composition and quality of the final pipeline blend. *Argus* assessments for US pipeline crudes are not meant to reflect any fixed gravity or sulphur content. Instead *Argus* assesses prevailing "stream quality" as it exits the pipeline system and is made available fob from the terminal, allowing the market to make determinations as to quality and value of pipeline grades. API gravity and sulphur content in the tables above are meant to be approximate guides only, and *Argus* does not apply escalators or de-escalators to US pipeline quotes to compensate for quality shifts.

Basis (Location)

Crudes are assessed fob at specific pipeline delivery terminals where spot trade is centered.

Volume
Trades in the US pipeline market are transacted at volumes expressed as barrels delivered per calendar day (b/d) or total barrels per month. A trade reported as 1,000 b/d for the month of March would be equivalent to 31,000 barrels total delivered rateably over the calendar month of March. Trades such as cash rolls, strips and boxes that are reported as total volumes are divided by the total number of days in the delivery month to obtain an equivalent volume expressed in barrels delivered per calendar day (b/d).

Timing and Roll Dates
Prices are assessed for the forward month in which the crude will be delivered. Month One assessments end after that month's pipeline scheduling deadline has passed. All US pipeline assessments roll on the fourth business day following expiry of the Nymex light sweet crude futures contract, which is the same as the first business day following the pipeline scheduling deadline.

Argus rolls its Bakken and WCS Cushing price basis forward on Canadian pipeline nominations day, also called initial NOS deadline, typically falling around the 20th calendar day of the month. So, for example, assuming the pipeline nominations deadline for March injected barrels is 17 February, Argus daily prices reflect April as the front month beginning on 17 February. Argus considers a new trade month to have begun on each pipeline scheduling day.

West coast pipeline

US West coast

Grade	API Gravity	% Sulphur	Basis	Low/ High Minimum Volume
San Joaquin Light Blend	28.5	1.10	Belridge Station, CA	1,000 b/d
Line 63	28.5	1.10	Hynes Station, CA	1,000 b/d
Midway Sunset	13.0	1.20	Station 36, CA	1,000 b/d

Low and High Prices
Argus assesses the range of trade for each grade over the entire day, subject to certain volume minimums depending on the grade. These numbers are displayed both as differentials to local postings - which the California market uses as its basis for trade in local grades – and as fixed prices. Deals must be 1,000 b/d or more to set either the low or high of the daily range. On illiquid days when there is insufficient trade to set the low or high value, *Argus* will assess the range in which trade could have occurred based on various market indications.

Postings Averages
Fixed prices for US west coast grades are based off an average of the relevant postings updated and available each night by 5:30pm Central time. These typically include Chevron, Shell and Phillips 66. The Light Postings Average serves as the basis for the San Joaquin Light Blend and Line 63 values, and is comprised of the Buena Vista postings issued by these companies. The Heavy Postings average is the basis for Midway Sunset values, and is comprised of the Midway Postings prices issued by these companies.

Implied WTI Diff
In order for US west coast crude values to be more easily compared with those for other crudes around the Americas, *Argus* converts the market's postings-based prices to an equivalent differential relative to the WTI Formula Basis.

Stream Quality
US pipeline grades are created by blending the output from many different fields flowing into a particular pipeline system. Production volumes and quality from individual fields can change, as can transportation logistics into or out of pipeline systems. Such changes inevitably alter the composition and quality of the final pipeline blend. *Argus* assessments for US pipeline crudes are not meant to reflect any fixed gravity or sulphur content. Instead *Argus* assesses prevailing "stream quality" as it exits the pipeline system and is made available fob from the terminal, allowing the market to make determinations as to quality and value of pipeline grades. API gravity and sulphur content in the tables above are meant to be approximate guides only, and *Argus* does not apply escalators or de-escalators to US pipeline quotes to compensate for quality shifts.

Basis (Location)
Crudes are assessed fob at specific pipeline delivery terminals where spot trade is centered.

Volume
Trades in the US pipeline market are transacted at volumes expressed as barrels delivered per calendar day (b/d). A trade reported as 1,000 b/d for the month of March would be equivalent to 31,000 barrels total delivered rateably over the calendar month of March.

Timing and Roll Dates
Prices are assessed for the forward month in which the crude will be delivered. Month One assessments end after that month's pipeline scheduling deadline has passed. All US pipeline assessments roll on the fourth *Argus* business day following expiry of the Nymex light sweet crude futures contract, which is the same as the first business day following the pipeline scheduling deadline.

Canada pipeline

Argus has structured Canadian crude oil assessments to reflect the unique market characteristics of each Canadian grade and to reflect the broadest possible array of market activity.

In Canada, *Argus* provides the following types of index prices:

Daily weighted average price: This method captures the entire day of deals done as a volume weighted average, which *Argus* publishes as a differential. This differential average is then applied to the day's Nymex settlement in order to provide an outright daily mark. This allows companies to connect their physical program with the hedging program on a daily basis.

Trade month weighted average price: This method produces a differential price that captures all deals done from the first business day of the month through pipeline nominations day as a volume weighted average. This allows companies to price oil in a manner compatible with current Canadian practice.

Low/high price range: These prices reflect the full range of deals done each day. This range is essential to assessing value in illiquid markets and reflects the true movement of prices over the trading day.

Argus values liquidity and seeks to reflect the breadth of the spot market. This leads *Argus* to create price indices that include deals done on all broker and exchange platforms, deals done bilaterally, and deals done through the entire trading day. With this price discovery methodology, *Argus* can provide a comprehensive total market index for all crudes assessed.

Crudes assessed according to volume-weighted average method:

Grade	Density (kg/m3)	API Gravity	% Sulphur	Pricing Basis	VWA Aggregate Volume Minimum	Low/High Minimum Volume
Syncrude (SYN)	860	31-33	0.1-0.2	Pembina AOSP at Edmonton	1,000 b/d; 159m3	500 b/d; 80m3
Western Canadian Select (WCS)	925	20-21	3.4-3.7	Husky at Hardisty	1,000 b/d; 159m3	500 b/d; 80m3

Basis (Location):

- *Syncrude (SYN)* – This assessment reflects synthetic crude produced by Syncrude Canada and delivered at the Edmonton terminus of Pembina's AOSPL (Alberta Oil Sands Pipe Line Ltd). Deals for SYN in the Edmonton pipeline/tank facilities of Enbridge are also considered in the index.
- *Western Canadian Select (WCS)* – This reflects WCS blend at Husky's facilities in Hardisty and includes in-line deals on the Enbridge pipeline system (EIL).

Volume Weighted Averages

The daily weighted average price for these grades is set by the volume weighted average of all deals during the trading day. The volume weighted average is calculated by multiplying the price of each deal (reported as a differential) by the volume of the deal, then summing the results and dividing by the total volume traded on that grade throughout the day.

The daily weighted average is stated as a differential and as an outright price. The outright price is derived by applying the weighted average differential price to the daily Canadian CMA.

There is no minimum volume threshold for including any individual deal in the daily volume weighted average. However, if the aggregate daily volume of trade for any grade fails to reach a specified minimum volume (see table), the daily volume weighted price for that day will reflect the mean of the low/high price range assessed for that grade on that day.

Trade Month Weighted Averages

Argus publishes a trade month weighted average price for the following grades:

- Syncrude (SYN) at Edmonton
- Western Canadian Select (WCS) at Hardisty

The trade month weighted average price calculates a cumulative weighted average of every deal done on that grade from the first business day of the month through the end of the business day prior to pipeline nominations day (also referred to as the deadline for notice of shipment /initial NOS deadline), which typically falls around the 20th calendar day of the month. For example, the trade month weighted average price for April-delivered barrels would include all deals done from March 1 to March 17 – assuming that the initial NOS deadline is March 18. It would not include trades done between initial NOS deadline in mid February and the first business day of March. This average parallels traditional practice by other leading indices that have been used in recent years in the western Canadian market.

The trade month weighted average is stated only as a differential, reflecting prevailing market trading practice. No outright equivalent price will be reported.

Syncrude and WCS deals reported to Argus up to one trading day after being concluded will be eligible for inclusion in the calculation of the trade month cumulative weighted averages. However, any deals that are reported to Argus the day after they were concluded will not form part of any calculation for daily weighted averages, neither for the day in which the deals were transacted (previous session) nor the day in which they were reported (current session).

Low and High Prices

For every grade of crude assessed, Argus publishes a low and high of deals done throughout the entire trading day. In order to qualify to set the low or high of the day, deals must meet the minimum volumes as specified in this methodology (see table at right). In illiquid markets, Argus pricing represents an intelligent assessment of the range within which a crude grade could have traded during the entire trading day.

Trading day

Argus considers all bona fide deals done and reported during the period from 7am-3:30pm, prevailing time in Calgary (Mountain Time), in the calculation of its low, high, and daily weighted average prices.

Timing and Roll Dates

Argus rolls its price basis forward on pipeline nominations day, also called initial NOS deadline, typically falling around the 20th calendar day of the month. So, for example, assuming the pipeline nominations deadline for March injected barrels is February 17, *Argus* daily prices reflect April as the prompt month beginning on February 17. *Argus* considers a new trade month to have begun on each pipeline scheduling day.

However, for purposes of the *Argus* trade month weighted average (Trade Month Wtd Avg), only trades for April-injected barrels traded from March 1 through March 17 would be considered.

Spot trade only

Argus indices are meant to be a reflection of spot trade done at a differential to WTI. Therefore, deals done as part of a strip or priced against another month or a grade other than WTI cannot be considered in the volume-weighted index. Deals priced against posted prices cannot be included in the index. Internal transfers between divisions of the same company cannot be considered as representative spot deals. Deals done conditional upon credit agreements or other pending arrangements will not be included in *Argus* price indices.

Canadian CMA

The Canadian CMA is calculated by extending the current day's Nymex prompt-month futures settlement for "Light Sweet Crude Oil (WTI)" until its expiry date, and extending the current day's second-month WTI settlement over the remaining days in the calendar month following prompt-month expiry. After the prompt month contract expires, the new prompt month is extended until the end of the calendar month.

Other Canadian Crudes assessed

In addition to providing volume-weighted prices for the most actively traded petroleum liquids streams in western Canada, *Argus* provides assessments of prices for other less-actively traded streams shown below. On days in which trade occurs on these grades, *Argus* will set its price range based on the highest and lowest price achieved on trades during the day. In order to set the high or low for the range, a deal must reach a certain volume threshold, shown in the tables.

Grade	API Gravity	% Sulphur	Pricing Basis	Low/High Minimum Volume
Condensate	61-65	0.08-0.20	Enbridge CRW pool at Edmonton	500 b/d; 80m3
Mixed Sweet (MSW)	39-40	0.45	Enbridge at Edmonton	500 b/d
Lloyd Blend (LLB)	20-21	3.47	Hardisty	500 b/d
Light Sour Blend (LSB)	38.0	0.88	Enbridge or Westspur at Cromer	500 b/d
Canadian CMA	39.0	0.40	Cushing, OK	

Stream Quality

Argus assessments are meant to reflect stream quality for each grade. The table above reflects stream quality as ascertained by *Argus* at the time of methodology publication, but it is assumed that the market is aware of fluctuation of quality in the streams and reflects those quality variations in the prices agreed between trading parties.

Americas Waterborne Markets

US Gulf coast waterborne

US Gulf coast

Grade	API Gravity	% Sulphur	Basis	Timing	Minimum Volume
Basrah Light	30.0	2.00	cif US Gulf coast	10-60 Days Forward	500,000 bl
Escravos	34.0	0.15	cif US Gulf coast	10-60 Days Forward	500,000 bl
Forties	40.3	0.56	cif US Gulf coast	10-60 Days Forward	500,000 bl
Kissanje	29.8	0.38	cif US Gulf coast	10-60 Days Forward	500,000 bl
Nemba	38.7	0.19	cif US Gulf coast	10-60 Days Forward	500,000 bl
Qua Iboe	36.6	0.13	cif US Gulf coast	10-60 Days Forward	500,000 bl
Saharan Blend	46.0	0.10	cif US Gulf coast	10-60 Days Forward	500,000 bl

Low and High Prices

Prices represent the low and high range within which oil traded or could have traded. Prices are published as differentials to Nymex light sweet crude futures and as fixed prices. Assessments of cargo values are at a fixed point in time. Outright prices are time-stamped at the US equivalent of 4:30 pm London time. The 4:30 pm London time stamp typically equates to 10:30 am Houston time except during the summer/winter time change in spring and fall when it may equate to 11:30 am Houston time. The WTI/Brent spread at 4:30 pm London time is used to calculate WTI differentials for cargo discussion taking place in the US Gulf coast on a Brent basis. Argus publishes both Ice Brent and Nymex WTI 1-minute markers at 4:30 pm London time. The Nymex WTI price at 4:30 pm London time is the basis price to which differentials are applied to obtain outright values. Trades and discussion for partial-cargoes of less than 500,000 bl are not included in the assessment process. Argus prices represent only full-sized cargoes of 500,000 bl volume and higher.

Quality

API gravity and sulphur content in the table above are meant to be approximate guides only. *Argus* assesses the program quality as loaded by the producing entity. *Argus* does not apply escalators or de-escalators to its delivered US assessments to compensate for variations in quality between individual cargoes.

Basis (Location)

Assessments are on a CIF basis. Lightering charges are included in the assessments. Trade and discussion for cargoes delivered into the Louisiana Offshore Oil Port (Loop), or for cargoes pricing FOB the mother vessel (ex-ship) are adjusted to include lightering charges before being included in the assessment process.

Timing

Assessments for waterborne crudes are a continuous series with no roll date. Prices represent physical cargoes that have delivery dates 10-60 days forward, and their timing is referred to as prompt in the daily report.

US West coast waterborne

US West coast

Grade	API Gravity	% Sulphur	Basis	Minimum Volume
ANS	32.3	0.89	CIF US west coast	300,000 bl
Oriente	24.0	1.40	CIF US west coast	360,000 bl

Low and High Prices

Prices represent the low and high range within which oil traded or could have traded throughout the trading day. Prices are published as differentials to Nymex light sweet crude futures, and as fixed prices. Oriente pricing represents full-sized Panamax volumes or higher, while ANS pricing represents cargo lots of 300,000 bl or above.

Quality

API gravity and sulphur content in the table above are meant to be approximate guides only. *Argus* assesses the program quality as loaded by the producing entity. *Argus* does not apply escalators or de-escalators to its delivered US assessments to compensate for variations in quality between individual cargoes.

Basis (Location)

Assessments are on a CIF basis.

Timing

ANS prices are quoted for the month of delivery, and roll forward as needed to accurately reflect current discussion and trade in the spot market. The delivered assessment for Oriente is a continuous series with no roll date, its price representing physical cargoes that have delivery dates 10-60 days forward. For Oriente cargoes, the timing is referred to as Dated (abbreviated "Dtd" in the daily report).

Canadian waterborne

Canada

Grade	API Gravity	% Sulphur	Basis	Timing	Minimum Volume
Hibernia	35.0	0.45	fob Whiffen Head, Newf.	10-45 Days Forward	500,000 bl
Terra Nova	33.2	0.48	fob Whiffen Head, Newf.	10-45 Days Forward	500,000 bl

Low and High Prices

Prices represent the low and high range within which oil traded or could have traded throughout the trading day. Prices are published as differentials to the North Sea Dated assessment at 4:30pm London time, and as fixed prices. Trades and discussion for partial-cargoes are not included in the assessment process. *Argus* prices represent only full-sized Aframax cargoes of 500,000 bl or more.

Quality

API gravity and sulphur content in the table above are meant to be approximate guides only. *Argus* assesses the program quality as loaded by the producing entity. *Argus* does not apply escalators or de-escalators to its Canadian waterborne assessments to compensate for variations in quality between individual cargoes.

Basis (Location)

The Canadian waterborne assessments represent crude for loading out of the Newfoundland Transshipment Terminal at Whiffen Head, Newfoundland. Insurance and freight costs are not represented in these assessments.

Timing

Assessments for Hibernia and Terra Nova are a continuous series with no roll date. Prices represent physical cargoes that have loading dates 10-45 days forward, and their timing is referred to as Dated (abbreviated "Dtd" in the daily report).

Latin American waterborne

Latin America

Grade	API Gravity	% Sulphur	Basis	Timing	Minimum Volume
Castilla Blend	18.8	1.97	fob Colombia	10-60 Days Forward	500,000 bl
Escalante	24.1	0.19	fob Argentina	10-60 Days Forward	500,000 bl
Isthmus Formula	33.6	1.30	fob Mexico	10-60 Days Forward	500,000 bl
Maya Formula	22.0	3.30	fob Mexico	10-60 Days Forward	500,000 bl
Napo	18.5	2.00	fob Ecuador	10-60 Days Forward	360,000 bl
Olmeca Formula	39.3	0.80	fob Mexico	10-60 Days Forward	500,000 bl
Oriente	24.0	1.40	fob Ecuador	10-60 Days Forward	360,000 bl
Vasconia	24.3	0.83	fob Colombia	10-60 Days Forward	500,000 bl

Low and High Prices

Prices represent the low and high range within which oil traded or could have traded in the trading day. Prices are published as differentials to Nymex light sweet crude futures, and as fixed prices. For Castilla Blend, Escalante and Vasconia, prices are also published as differentials to Ice Brent crude futures. Trades and discussion for partial-cargoes are not included in the assessment process. *Argus* prices represent only full-sized Panamax cargoes of 360,000 bl or more for Oriente and Napo, and full-sized Aframax cargoes of 500,000 bl and higher on all other fob quotes from Latin America.

Mexican Formulas

Prices for Isthmus, Maya and Olmeca are represented as single prices, the result of using *Argus* prices in Mexico's formula for each grade. The resulting calculation is shown both as a differential to Nymex light sweet futures and as a fixed price. The K-Factor adjustments to formulas, revised monthly by Mexico, are also displayed and taken into account when prices are calculated. The formulas for the three Mexican grades are as follows:

Isthmus: (0.40 *Argus* volume-weighted WTS) + (0.40 *Argus* volume-weighted LLS) + (0.20 *Argus* North Sea Dated) + K Factor

Maya: (0.40 *Argus* volume-weighted WTS) + (0.40 *Argus* USGC 3pc fuel oil) + (0.10 *Argus* volume-weighted LLS) + (0.10 *Argus* North Sea Dated) + K Factor

Olmeca: (0.333 *Argus* volume-weighted WTS) + (0.333 *Argus* volume-weighted LLS) + (0.333 *Argus* North Sea Dated) + K Factor

Quality

API gravity and sulphur content in the table above are meant to be approximate guides only. *Argus* assesses the program quality as loaded by the producing entity. *Argus* does not apply escalators or de-

escalators to its assessments to compensate for variations in quality between individual cargoes.

Basis (Location)

All Latin American cargo assessments represent crude prices for loading at the port of origin. Insurance and freight costs are not represented in these assessments.

Timing

Mexican prices (Isthmus, Maya, Olmeca) are calculated for the current calendar month. All other Latin American assessments represent a continuous series with no roll dates, for cargoes loading 10-60 days forward.

Updates

For the publication schedule check www.argusmedia.com.
The *Argus Americas Crude* methodology is constantly updated and revised. The latest available methodology (which may supersede the one you are reading) is available at www.argusmedia.com.

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The Major Challenges Facing the Future of Oil Sands Development

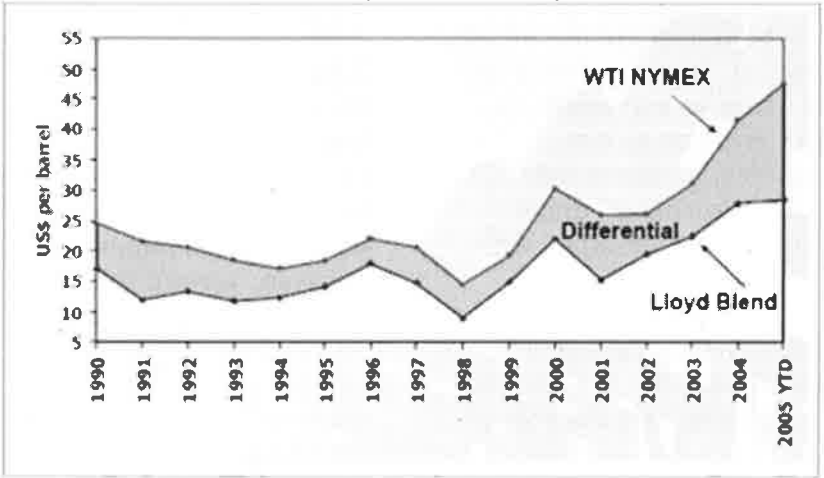
This blog chronicles the challenges and triumphs in developing Alberta's oil sands.

Thursday, January 17, 2008

Pricing - Light/Heavy Differentials

Canadian heavy crude oil prices are generally set by Midwest refining economics. Global light / heavy crude spread ultimately sets the price for oil sands blends.

According to Purvin and Gertz, a major independent energy consulting firm, The light/heavy differential significantly increases the profitability of upgrading the bitumen to a synthetic crude oil. The Lloyd blend heavy sour oil was worth



$57 on November 2, 2007. NYMEX WTI was around $96. Upgrading of the bitumen to a synthetic crude oil (SCO) that is comparable to WTI would cost $12.

While SCO commands a premium price to WTI and is in many ways comparable to light sweet crude, the high aromaticity of bitumen from which it is derived limits its penetration into refineries that are not specially equipped to handle it. A typical refinery is limited to between 10-20% of SCO in its crude slate. Part of the solution lies in additional technical/infrastructure capability in existing or new refineries and another lies in producing a higher quality light sweet synthetic crude, something being planned by a few of the new oil sands projects.

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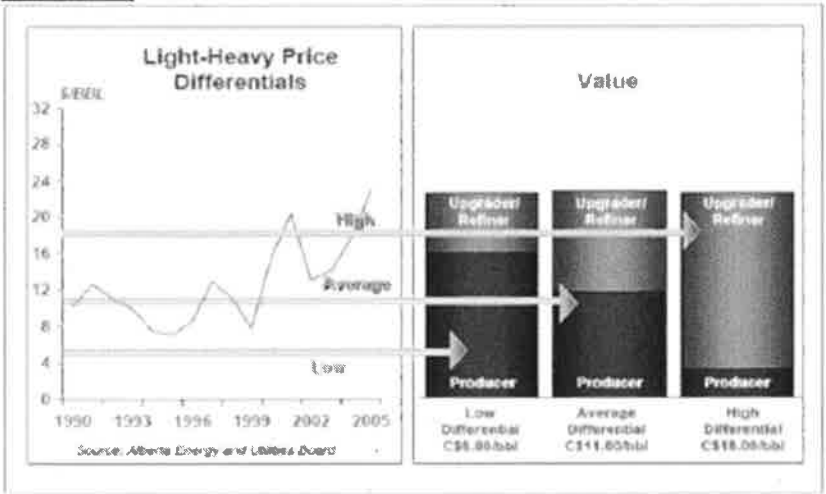
According to the Canadian Association of Petroleum Producers:



Synthetic Crude Oil (SCO) trades at a **premium** to WTI
-Current: $ 1US/bbl
Bitumen Blends trade at a **discount** to WTI
-Current: $ 23 US/bbl

Unprocessed bitumen is also marketed, but for pipeline transportation reasons must be shipped in diluted form. It sells at a considerable discount to synthetic crude as can be explained by the light-heavy differential: because heavy oil is worth less to a refiner, it typically sells at a discount to light oil. This difference in price is referred to as the differential. When the differential widens, it means that heavy oil is trading at a larger discount to light oil and it fetches a lower price. Bitumen is discounted yet again with respect to heavy oil.

Therefore, refiners are able to profit significantly from the end products. Petro-Canada has calculated that the bitumen netback depends on value of bitumen blend and the cost of diluent.
The Canadian Association of Petroleum Producers state that in recent years, slower natural gas growth, a shift to producing drier gas with less pentanes and competing demands for natural gas liquids have constrained available supplies of condensate.

Escalating prices and insufficient condensate supplies combined with growing supplies of heavy/bitumen crude that need a source of diluent have forced producers to examine other options. As a replacement for condensate, producers of oil sands bitumen are starting to use light synthetic crude oil as an alternative source of diluent for blending to pipeline viscosity requirements. This trend to use synthetic crude have led to the evolution of a synthetic bitumen blend referred to as Synbit. Synbit is more leveraged due to the

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Oil Sands News

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Utah Tar Sands: Will The
Huffington Post
While record numbers of protesters were chaining themselves to construction equipment earlier this week along the Oklahoma segment of the Keystone XL pipeline, the proposed plan to ferry Canadian tar sands to refineries on the U.S. Gulf Coast, another ...

2 Energy Giants Bucking
Motley Fool
When it comes to Canadian oil sands, there has been one direction that many a company has followed: toward the exit. Tough economics, as well as a lack of sufficient takeaway capacity, has made oil sands production difficult for oil companies. But ...

Two Major Lawsuits Filed
De Smog Blog (blog)
Two major lawsuits were recently filed in the U.S. District Court for the Eastern District of Arkansas against ExxonMobil, the "private empire" behind the March 2013 Pegasus tar sands pipeline spill of over 1.1 million gallons of diluted bitumen ...

higher diluent ratio, lowering netback. Therefore, lower diluent costs increases the bitumen netback

There are a lot of proposed pipeline expansion projects that aim to be able to move the SCO to markets with significantly more refining capacity. This will decrease the amount to which bitumen is currently being discounted.

There are also a number of projects underway to increase the refining capabilities of bitumen and synthetic crude oil.

Posted by Chris McManaman at 9:51 AM

Labels: Pricing

1 comment:

Chris McManaman said...

http://gembaoilsands.blogspot.com/

February 19, 2008 at 3:27 PM

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ENBRIDGE INC - Enbridge 4-traders (press release) Environmental regulators have been to the site and Enbridge is providing regular updates on methodology and status of the clean-up and remediation. Repairs to Line 37, which serves the Long Lake oil sands project, are continuing. However, completion of ...

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Introduction

Forecasted Oil Sands Production

Influences on Oil Sands Development

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Supply Costs - Development Costs

Supply Costs - Natural Gas Costs

Supply Costs - Diluent Availability

Crude Oil Supply - Electricity Requirements

Crude Oil Supply - Natural Gas Usage

Crude Oil Supply - Natural Gas Costs per Barrel

Crude Oil Supply - Natural Gas Supply

Crude Oil Supply - Status of projects to increase ...

Crude Oil Supply - Project Realization Probabiliti...

Crude Oil Supply - Project Costs by Type

Crude Oil Supply - SCO and Bitumen Supply Costs

Crude Oil Supply - Natural Gas Demand

Crude Oil Supply - Forecasted Excess Cogeneration

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► November (3)

► December (2)

EPA United States Environmental Protection Agency

Technology Transfer Network
Clearinghouse for Inventories & Emissions Factors

TANKS Emissions Estimation Software, Version 4.09D

Released October 5, 2006

- System Requirements
- How to Get *TANKS* 4.09D
- What's new in 4.09D?
- Errors and fixes in 4.09D - **Please see the information regarding monthly emissions results in TANKS. Added August 2012.**
- *TANKS* Frequently Asked Questions
- Who to contact for more information

What Is *TANKS*?

TANKS is a Windows-based computer software program that estimates volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions from fixed- and floating-roof storage tanks. *TANKS* is based on the emission estimation procedures from Chapter 7 of EPA's *Compilation Of Air Pollutant Emission Factors* (AP-42). The user's manual, available in Adobe Acrobat format and WordPerfect, explains the many features and options of *TANKS*. The program includes on-line help for every screen.

Audience

TANKS is designed for use by local, state, and federal agencies, environmental consultants, and others who need to calculate air pollutant emissions from organic liquid storage tanks.

Program Capabilities

TANKS uses chemical, meteorological, roof fitting, and rim seal data to generate emissions estimates for several types of storage tanks,including:

- vertical and horizontal fixed roof tanks
- internal and external floating roof tanks
- domed external floating roof tanks
- underground tanks

See the *TANKS* FAQ for additional information about *TANKS*.

The *TANKS* program employs a chemical database of over 100 organic liquids, and a meteorological database of over 240 cities in the United States. The program allows the addition of more chemicals and cities, if desired. *TANKS* is capable of calculating individual component emissions from known mixtures and estimating emissions from crude oils and selected refined petroleum products using liquid concentration HAP profiles supplied with the program.

System Requirements

TANKS 4.09 will run on Windows XP desktops. The program requires 8 MB of random access memory (RAM). The installed program requires 8 MB of available hard disk space. *TANKS* is designed for operation from a PC's hard drive. Many users are able to share tank databases via LAN connections to increase the utility of the program.

You must have administrative rights to all folders on your desktop. The installation process installs files to the Windows system directory.

TANKS is not supported on desktops using Windows Vista or Windows 7. Suggestions and fixes for running TANKS on a Vista or Windows 7 platform will be posted whenever possible. Please see the "Errors and fixes" table below.

Installations requiring TANK program files to be resident on a LAN are not advisable and are beyond our support capabilities.

TANKS Support

For help with the TANKS program, please send your question in an email to

info.chief@epa.gov.

How To Get A Copy Of *TANKS*

Version 4.09D of the *TANKS* software is available here.
You are advised to bookmark this web site and check it from time to time for information about updates to the TANKS program. Alternatively, you can **subscribe to the CHIEF listserv** and receive information about TANKS updates via email.

TANKS 4.09D - October 3, 2005 TANKS 4.09D supersedes all previous versions of the TANKS software program.	
What's new in 4.09D? • The program is now compatible with all versions of MS Access. • The program installation has been streamlined and the program files are smaller. • TANKS displays and prints reports with an Internet browser. The report formats have not changed. • Chemical Data: ◦ The chemical data was updated with missing CAS numbers. ◦ New compounds were added to the database. ◦ Antoine's coefficients were corrected for several compounds. ◦ A new partial speciation profile for gasoline oxygenated with ethanol was added. • Incorrect meteorological data was corrected.	
Installation instructions - PLEASE READ	(TXT 2K)
TANKS 4.09D Installation File Windows Installer file	(MSI 6.5M)
User's Manual for TANKS 4.0 The manual has not been updated	(PDF 646K)
***Alternate* TANKS 4.09D Installation File** If the Windows Installer file does not correctly install, use this file. Please read the installation instructions.	(EXE 12M)

Explanation of File Formats http://www.epa.gov/ttnchie1/software/tanks/

TANKS 4.09D errors and available fixes

PROBLEM	FIX
Determining monthly emissions. One of the errors in TANKS is that it uses annual average liquid bulk temperature when computing monthly emissions rather than calculating a monthly liquid bulk temperature. Since TANKS uses annual average liquid bulk temperature in the monthly calculations, a change in the temperature for one month will affect every month, in that changing one month changes the annual average. As such, the TANKS program will NOT adequately account for the monthly variations. Therefore, TANKS should NOT be used for determining maximum monthly true vapor pressure and users should not rely on the TANKS model for accurately determining monthly emissions in general. Users should rely on the equations specified in AP-42 Chapter 7.1 to perform those calculations.	Use section 7.1 of AP42, Organic Liquid Storage Tanks to correctly calculate monthly emissions.
There are revised deck fitting loss factors in the 2006 update to section 7.1 of AP42, Volatile Organic Liquid Storage Tanks. How can I include those in my TANKS program?	Updating the fitting table in TANKS (PDF 101K) For more detailed information about the deck fittings, see section 7.1 of AP42, Organic Liquid Storage Tanks
When I create a MS Excel or MS Access report from TANKS, I don't know what all the fields mean.	Field descriptions for MS Excel and MS Access reports from TANKS (PDF 50K) For more detailed information about the fields, see section 7.1 of AP42, Organic Liquid Storage Tanks
MS Vista users: TANKS does not run.	Possible solution for Vista users (ZIP 40K)
Internet Explorer version 7 users: The report function won't work and program locks up.	Possible solution for IE 7 users (TXT 2K)
Some of the partial speciation profiles that come with version 4.09D do not work.	Instructions for updating chemical database (PDF 8K)
Chemicals added and Antoine's coefficients corrected in 4.09D.	Additions to TANKS 4.09D (TXT 4K)
Error 1935 during installation.	Use the alternate installation provided above. Follow the installation instructions.
Could not find installable ISAM error message, or 'The wizard is unable to access information in the file.'	In Windows Control Panel open 'Regional and Language Options' and add your language.
TANK reports blocked as pop-up or Active X not allowed.	Best available solution (TXT 1K)

Last updated on Thursday, November 29, 2012

Recent Becht News

Changing Your Crude Slate?

24 May 2013

Changing Your Crude Slate? You Need to Consider More Than Just Naphthenic Acid Corrosion and High Temperature Sulfidation.

Refiners are constantly evaluating their crude slates in an effort to maximize profits. It involves a continuous effort in trying to get the most product value from the lowest cost crudes. Generating a $1.00 per barrel margin on a crude slate, taking into consideration both product value and cost of the crudes in the slate, can create more than an 100M$ advantage over the course of a year for a refinery processing 300,000 barrels a day. This large advantage can be turned into a large loss with a single related equipment failure which results in weeks of unit shutdown.

Typically, when a refiner evaluates a crude change the primary considerations from an equipment reliability and safety standpoint are naphthenic acid corrosion and high temperature sulfidation. Many studies have been conducted that evaluate the effect higher TAN and sulfur crudes have on the corrosion experienced by equipment in crude and other downstream units. However, these are not the only forms of corrosion or damage that can be experienced by equipment as the result of a crude change. This article presents several examples of how a change in crude slate can have other adverse effects on equipment reliability and safety. These examples include the following:

Sulfidation from Light Crudes and Condensates

New light crudes and condensates from the Middle East and the countries on the Caspian Sea contain higher levels of lighter sulfur compounds such as mercaptans and disulfides. The corrosion rates caused by these lighter sulfur compounds are not accurately predicted by conventional high temperature sulfidation corrosion curves such as the McConomy curves. When these lighter crudes and condensates are added to a crude slate they do not significantly increase the overall weight percent sulfur in the crude slate; however, these lighter sulfur compounds concentrate in the lower boiling temperature naphtha fraction and significantly affect sulfidation observed in the naphtha stream when heated in a naphtha hydrotreating unit. Sulfidation can be particularly aggressive in 5 Cr tubes in the convection section of a naphtha hydrotreating furnace at a location in the coil where the naphtha completely vaporizes.

Desalting Difficulties

New crudes can frequently introduce desalter operating difficulties. Recent experience has shown that heavy high TAN crudes tend to form strong emulsions in desalters that require enhanced chemical additions and modifications to the desalter operation in order to avoid carryover that causes increased pre-heat train fouling, furnace coking and overhead corrosion. Additionally, some of the new crudes also have higher fine particulate levels that can be difficult to remove/reduce in a desalter. The particulates have caused increased fouling in equipment processing bottom streams.

Corrosion in Vacuum Overhead Circuits

Experience has shown that higher TAN levels in the feed to vacuum crude units promote the hydrolysis of inorganic salts, like sodium chloride, in the furnace to form HCl that promotes overhead corrosion. In the past, when running low TAN crude slates, salts in the vacuum unit feed did not hydrolyze to form HCl and overhead corrosion was not a concern. It was common that chloride levels in the overhead water of a vacuum unit were below 5 ppm. Today, it is common that the overhead water has chloride levels exceeding 50 ppm requiring corrosion control measures similar to the measures to control corrosion in the atmospheric crude unit overhead. These measures include neutralizer and corrosion inhibitor addition, water injection and selective use of alloy.

Increased Corrosion in Amine Treating Units

Naphthenic acid decomposes into carbon dioxide (CO_2) and water in a hydrotreating unit reactor. In some refineries that have increased their TAN levels in the crude slate, this has caused increased CO_2 levels in the hydrogen treat gas. When the hydrogen treat gas with elevated levels of CO_2 is processed in the amine treating

Upcoming Events

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Mon Aug 12
ASME B31.3, Process Piping - Design, Construction, and Mechanical Integrity
Becht Engineering's West Coast Office, 2415 Campus Dr., Suite 275, Irvine, California 92612

Mon Aug 12
ASME Boiler and Pressure Vessel Committee
Montreal

Mon Aug 19
ASME Section VIII, Division 2 - Part 5, Design-By-Analysis
Becht Engineering's West Coast Office, 2415 Campus Dr., Suite 275, Irvine, California 92612

Mon Aug 26
ASME PCC-2 Repair of Pressure Equipment & Piping
Becht Engineering Offices, 2415 Campus Dr., Suite 275, Irvine, CA 92612

Mon Sep 16
B31 Code Week - Fall 2013
South Portland, ME

Tue Sep 24
ASME Section VIII, Division 1 Pressure Vessel Design
Eagle Pointe Recreation Complex, 12450 Eagle Pointe Drive, Mont Belvieu (Houston area), TX 77580

Mon Sep 30
ASME PCC-2 Repair of Pressure Equipment & Piping
Eagle Point Golf and Recreation Complex, 12450 Eagle Pointe Drive, Mont Belvieu (Houston area), TX 77580

Mon Sep 30
ASME Section VIII, Division 2 - Part 5, Design-By-Analysis
Wingate Hotel, 400 Midpark Way SE, Calgary, Alberta T2X 3S4, Canada

Mon Oct 07
ASME B31.3, Process Piping - Design, Construction, and Mechanical Integrity
Eagle Point Golf and Recreation Complex, 12450 Eagle Pointe Drive, Mont Belvieu (Houston area), TX 77580

Tue Oct 15
ASME PCC-2 Repair of Pressure Equipment & Piping
Wingate Hotel, 400 Midpark Way SE, Calgary, Alberta T2X 3S4, Canada

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unit, the increased levels of CO2 in the rich amine stream and the regenerator overhead circuit have resulted in an increase in the observed corrosion in these circuits.

Increased Wet H2S Cracking

A refinery recently backed out a heavy high sulfur crude from its slate and replaced it with a heavy low sulfur high TAN crude. At the same time they noticed a dramatic increase in wet H2S cracking damage (hydrogen blistering and through wall HIC damage) of equipment in the cat light ends unit. This same refinery had previously discontinued ammonium polysulfide (APS) injection into the cat light ends feed stream because they found when processing the high sulfur crude it was not needed. However, when substituting the heavy low sulfur high TAN crude for the heavy high sulfur crude, there was inadequate sulfur present without APS injection to maintain the protective sulfide scale on equipment surfaces to protect it from wet H2S cracking in this high cyanide (CN^-) environment.

These examples demonstrate that when evaluating a new crude slate it is necessary to consider all possible damage mechanisms that can affect equipment. It is not just a matter of evaluating naphthenic acid corrosion and high temperature sulfidation. These damage mechanisms are important but they are not the only damage mechanisms that can affect equipment reliability and safety when changing a crude slate.

Jim McLaughlin, Becht Engineering Senior Advisor

Training and Qualification of Bolted Joint Assembly Personnel

24 May 2013

For quite some time now, Section VIII Division 1 of the ASME Boiler & Pressure Vessel Code has included the following provision in Appendix 2-15:

> **2-15 QUALIFICATION OF ASSEMBLY PROCEDURES AND ASSEMBLERS**
>
> It is recommended that flange joints designed to this Appendix be assembled by qualified procedures and by qualified assemblers. ASME PCC-1 may be used as a guide.

The "qualified procedures" reference is to Appendix A of PCC-1-2010 entitled "Notes Regarding Qualifying Flanged Joint Assemblers" and these notes cover slightly less than ½ page, with an Introductory Note stating that a proposed revision to this Appendix was under consideration by the ASME Pressure Technology Post Construction Committee. Well this "consideration" has come to fruition so that the updated Appendix A in the 2013 Edition of PCC-1 will include a replacement 20+ page Appendix A entitled:

TRAINING AND QUALIFICATION OF BOLTED JOINT ASSEMBLY PERSONNEL

QUALIFICATION COMPONENTS

There are three components outlined in the new Appendix A for Qualification of a Bolting Specialist:

- Training – a training course that meets the guidance provided in Appendix A, including examination on the theory.
- Practical – successful completion of a combined practical examination and practical demonstration
- Experience – a requirement of a certain level of field experience

TRAINING OF FUNDAMENTALS

Training in the fundamentals of bolted joint operation and assembly includes instruction in over 20 areas, including:

- General personal joint assembly equipment requirements
- The principles of bolt elongation
- Bolt load and gasket stress
- Functionality of gasket and seal
- Gasket types and their limitations
- Bolt types and their limitations
- Identification of correct joint components
- Manual Torque joint tightening
- Importance of using the specified lubricant
- Techniques used for load control
- Calibration and maintenance of bolt tightening equipment
- Inspection and reporting defects or faults
- Procedure for preparing a joint for closure
- Gasket handling, preparation and installation
- Sources of information on joint assembly
- Safe joint disassembly and assembly
- Joint assembly procedures
- Ensuring correct use of additional joint components
- Importance of procedures, qualification and records
- Joint Disassembly

PRACTICAL DEMONSTRATION

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PIPELINE CONGLOMERATE BUYS CONTRACTOR BRINDERSON

Aegion Corp. eyes California construction firm's track record in upstream and downstream oil and gas markets; contractor's senior managers to remain.

TEST DRIVE: DEERE 644K HYBRID WHEEL LOADER

Deere's 644K Hybrid wheel loader is the company's first hybrid construction machine.

FOXX CONFIRMED UNANIMOUSLY AS DOT SECRETARY

Foxx's top construction-related task will be finding new revenue to shore up ailing Highway Trust Fund.

In addition to training on the theory of joint operation and assembly, different practical demonstrations are required; each designed to clarify one of the following important aspects:

- Importance of bolt assembly pattern
- Importance of bolt assembly pattern versus correct gasket selection
- Importance of joint alignment prior to assembly
- Importance of gasket placement
- Influence of bolt & nut lubrication
- Reaction of different types of gaskets to standard tightening procedures

PRACTICAL EXAMINATION & FIELD EXPERIENCE

To complete the training aspect of the qualification program, the candidate will be required to take a practical examination that consists of assembling at least 2 joints while being graded by a Qualified Bolting Specialist Instructor. In addition, there are supplementary training requirements for the optional endorsements to the qualification that focus specifically on aspects that are covered by the field of endorsement (such as the operation of hydraulic equipment for powered equipment endorsement).

Since the practice of assembling a joint in the field provides a significant source of learning for the individual, Appendix A also outlines a minimum amount of experience of bolted joint assembly in the field that is required before an individual can be considered a Qualified Bolting Specialist. The requirement is for 6 months of full time experience, with part time experience being pro-rated depending on the amount of actual assembly experience that the individual is receiving in their day-to-day activities.

INTENDED IMPLEMENTATION

The intent of Appendix A is to provide a sound basis for the training, assessment and qualification of bolted joint assemblers, but it is fully recognized that qualifications of this level are not required for every individual involved in the assembly of every joint. In fact, it is common for joints to be assembled using teams of individuals with different skill sets, and it is fully expected that in the best case scenario only one or two individuals may actually be Qualified Bolting Specialists on any given team. It is felt that, through the process of ensuring this potential step change improvement in the knowledge of the team, as a whole, that the intent of the Appendix will have been achieved.

HOW PROGRAM WILL BE ADMINISTERED

In order to achieve the desired goal, a system of independent third-party verification was developed, which was designed to demonstrate that the qualification programs are in accordance with Appendix A. This approach is similar to an accreditation program, with the exception that there is no central body administering the accreditation. A While the selected approach is perhaps not as good as a true accreditation program in achieving portability, the advantage is that it does allow industry to customize and find a system that will be both practical and efficient for providing the desired end result of assembler qualification. The other advantage is that the lack of a centralized body means that the program growth and implementation is not limited by the capabilities or resource of the centralized body.

FINAL THOUGHT

Our final thought on implementation is that end-users should be cognizant of the difference between assembler qualification and assembler competency. The Appendix A program has been formulated to try to maximize the likelihood that a qualified assembler will also be a competent assembler by the inclusion of experience and practical examinations/demonstrations. However, in the end it is only by witnessing the individual at work over an extended period of time that competency can truly be judged, such as the system for on-going inspection and testing of welder performance which is required to maintain their qualifications. Therefore, the onus for determining the competency of an assembler will remain the responsibility of their employer, even if they may hold a joint assembler qualification.

Clyde C. Neely, Becht Engineering Fellow

A Lift Plan for Every Lift

22 March 2013

Ten Questions That Must Be Answered Before Attempting Any Lift

When attempting any lift, regardless of how small or seemingly insignificant, there is some basic information that must be known and confirmed before you begin. As an industry, we do a great job planning critical and super lifts. These major lifts are executed with precision and are successful if the plan is carefully followed. We don't do as well on the everyday routine or standard lifts. In most cases there is little or no planning and when things go wrong, accidents result. In my experience, the majority of crane accidents result from lifts that are classified as standard when in fact there is nothing standard about any lift.

There are ten questions that must be answered for any lift and could be considered a basic lift plan for standard lifts. The ten questions can be converted into a simple lift plan form. Then, require the crane operator to complete it before each and every lift. It only takes a few minutes and could prevent a costly accident. It has been shown that when a lift plan is required for every lift, the supervisors, operators and riggers catch mistakes before they happen.

For example: The lift could be at a high percent of capacity. The crew may need to move the crane a few feet to reduce the radius, significantly improving the capacity and safety of the lift.

The Ten Questions that must be answered include:

1. **WHAT IS THE "VERIFIED" WEIGHT OF THE LOAD?** It is not possible to make a safe lift when the weight of the load is not known or verified. Many smaller loads can be easily calculated; such as a bucket of concrete or a steel beam. Most loads are shipped to the work site by truck; the trucking company weight ticket is a good source for weight information.In any case, the load weight is critical and must be known and verified

2. **WHAT IS THE MAXIMUM RADIUS?** The radius is defined as the distance between the center of rotation of a crane and the center of gravity of a freely suspended load. The radius must be known and should be measured. At a minimum, a dry run should be preformed by placing the empty hook over the pick and set locations; measuring radius for each case. Calculate the lift according to the farthest distance.

3. **WHAT IS THE RIGGING CAPACITY AND WEIGHT?** Calculate the capacity of the rigging configuration. The system is only as strong as the weakest link. Consider the effect of sling angles on the rigging and try to maintain angles of 60 degrees, or higher, to horizontal. A sling angle of thirty degrees to horizontal results in a force of two times the force applied to a vertical sling. Calculate the effective weight of the rigging system and record it on the plan. The weight of the entire rigging system is deductible from the crane chart gross capacity

4. **WHAT ARE THE APPLICABLE CAPACITY CHART DEDUCTIONS?** Once a crane is configured it is usually not changed often. A suggestion is to add all the deductible crane accessories and make a note of the combined deductions. Then all the operator has to do is add the weight of the rigging to the accessory total and subtract the combined total from the "gross" capacity to obtain the "net" capacity. Everything hanging under the boom top is considered part of the load. Don't forget to include deductions for attachments that are mounted on the boom and not used; such as jibs or boom extensions.

5. **WHAT IS THE CRANE "NET" CAPACITY AFTER DEDUCTIONS?** ***(At the maximum radius and crane configuration)*** Very often accidents occur because the operator relies solely on the "gross" capacity from the crane chart. All deductible items must be subtracted from the "gross" capacity to establish the "net" capacity.

6. **IS THE CRANE ON FIRM LEVEL GROUND?** Ground bearing calculations and soils analysis are not practical for every lift made by small cranes. Matting should always be used; without exception. Due their small size, the manufacturers' outrigger floats (pads) are not designed to stand-alone and do not provide an acceptable load distribution. Check to see if there has been a recent excavation in the set up area. A sure sign of trouble is when the crane tires sink into the ground while driving into position. A simple approach to matting size is to divide the crane rated capacity by 4. Then take the square root of the dividend. The result can be considered the length of one side of a square mat. This method is only a starting point and will not be sufficient in every case. Be sure to make the mat to strong enough to resist bending so as not to reduce the load distribution to the ground.Example: 50 ton crane / 4 = 12.5; the square root of 12.5 = 3.53 so your square mat should be a minimum of 3.5 feet for each side.

7. **ARE THERE POWER LINES ANYWHERE IN THE PATH OF THE LOAD OR CRANE ATTACHMENTS?** Search for power lines and sources of electric energy before moving the crane into position. Note the locations and record them on the lift plan. Discuss the lift plan with all persons evolved so that everyone is aware of a potential hazard. A designated spotter is required to warn the crane operator of an impending contact. Beware of power lines that are hidden within tree branches or behind buildings. Statistically, power line contact is most occurring crane accident worldwide. These accidents out number all other crane accidents combined.*See the OSHA Power Line Rule found in the Subpart CC - 1926.1400 standard at www.osha.gov for more information and direction.*

8. **ARE THERE OBSTRUCTIONS ANYWHERE IN THE PATH OF THE LOAD OR CRANE ATTACHMENTS?** Check the work area for obstructions. Make a dry run through the full swing path of the proposed lift and observe the boom clearance to any obstructions.

9. **WILL THE LOAD CONTACT THE CRANE BOOM OR JIB AT ANYTIME DURING THE LIFT?** Is the load long and can it contact the boom or jib during the lift? If a load contacts a loaded boom, the boom could collapse. Will there be room to turn a long load for alignment during the lift? Always use non-conductive tag lines to control the load.

10. **WHAT IS THE RATIO OF CRANE CAPACITY TO NET LOAD?** Calculate the percent of chart capacity by dividing the load weight by the net capacity. When a crane is nearing capacity everything has to be exactly right. If anything goes wrong it happens fast there is little chance to recover. Percent of chart often defines a critical lift and an additional, comprehensive, "Critical Lift Plan" may be in order. It is advisable to establish a definition and procedure for a "Critical Lift". It is advisable to require the completion of a more comprehensive "Critical Lift" plan when the "Ten Question" plan indicates the lift has met the criteria for

critical lift. It has been observed that when the ten-question lift plan indicated it is a critical lift; the crew will re-think the set up and lift parameters, there by reducing the percent of capacity to a more reasonable, lower ratio.

"CASE STUDY" MASSIVE BRIDGE CONSTRUCTION PROJECT

The project experienced three major crane accidents during the first month of construction. After consultation with the author, the Project Manager created a ten question lift plan and made it mandatory for every lift and required a critical lift plan for any lift over 85% of chart. The critical lift plan had to be approved by the Project Manager or the designated Lift Specialist. The 10-question lift plan for every lift was a condition of employment and strictly enforced. The project was completed, in three years, on time and under budget without an additional crane related accident or incident. The project management team observed that all craft supervisors with crane related responsibilities became creative about how they set up the cranes. In many instances they were able to effect minor changes to the crane set up locations, improving the lift parameters resulting in lifts rated well below the critical lift criteria.

It should be understood that there are many things that affect the safety of a lift. The ten-question lift plan is intended to inspire creative thinking and assure the most vital parameters are considered. It does not, in any way, relieve the crane operator or rigging crew from their responsibilities to consider everything that may affect the safety on any lift.

Joe Collins, Becht's Heavy Lift Manager

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cenovus ENERGY

LIGHT CRUDE OIL

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

Product Identifier: LIGHT CRUDE OIL
Synonyms: Bakken Oil, Bakken Crude
Chemical Description: A naturally occurring mixture of aromatic hydrocarbons and small amounts of sulfur and nitrogen compounds
Product Use: Process stream, fuels and lubricants production
Manufacturer/Supplier: CENOVUS ENERGY INC.
500 Centre Street SE, PO Box 766
Calgary, AB T2P 0M5
Prepared By: Cenovus Energy Inc. Health and Safety
Phone Number: 1-403-766-2000
Emergency Telephone: 1-877-458-8080, CANUTEC 1-613-996-6666 (Canada)

2. COMPOSITION/INFORMATION ON INGREDIENTS

Hazardous Ingredients	CAS Number	Approximate Concentration (%)
Petroleum Crude Oil	8002-05-9	100 v/v
Benzene	71-43-2	0.1 – 1.0 v/v

Hydrogen Sulfide in liquid is <0.1% v/v, vapour phase may contain higher concentrations.

3. HAZARDS IDENTIFICATION

Routes of Entry: Skin contact, skin absorption, eye contact, inhalation, ingestion
Emergency Overview: Warning. Flammable liquid and vapour. Liquid and vapour may cause irritation or burns to eyes, nose and throat. Inhalation of vapour may cause dizziness and drowsiness. Possible cancer hazard (benzene). Possible asphyxiation hazard (hydrogen sulfide). Wear personal protective equipment appropriate for the task.

WHMIS B2, D2-A, D2-B
NFPA F4, R0, H3

Potential Health Effects: Contains material which may cause cancer after long-term, repeated skin contact.

4. FIRST AID MEASURES

Eye Contact: Immediately flush eyes with large amounts of lukewarm water for 15 minutes, lifting upper and lower lids at intervals. Seek medical attention if irritation persists.

Skin Contact: Remove contaminated clothing. Flush skin with water. Get medical attention if irritation persists or large area of contact. Decontaminate clothing before re-use.

Inhalation: Ensure own safety. Remove victim to fresh air. Give oxygen, artificial respiration, or CPR if needed. Seek medical attention immediately.

Ingestion: Give 2-3 glasses of milk or water to drink unless patient is unconscious or has a decreased level of alertness. DO NOT INDUCE VOMITING. Keep patient warm and at rest. Seek medical attention immediately.

5. FIRE FIGHTING MEASURES

Flammable: Material will ignite at normal temperatures.
Means of Extinction: Foam, carbon dioxide (CO_2), dry chemical. Explosive accumulations can build up in areas of poor ventilation.
Special Procedures: Use water spray to cool fire-exposed containers, and to disperse vapors if spill has not ignited. Cut off fuel and allow flame to burn out.
TDG Classification: 3
Flash Point (°C) & Method: <-35 (PMCC)
Auto-Ignition Temp. (°C): 250 (estimated)
Upper Explosive Limit (% v/v): 8 (estimated)
Lower Explosive Limit (% v/v): 0.8 (estimated)
Sensitivity to Impact: No
Sensitivity to Static Discharge: Yes, at normal temperatures
Hazardous Combustion Products: Carbon monoxide, sulfur oxides, nitrogen oxides, smoke particles
NFPA 704 Rating: Flammability:4, Instability/Reactivity:0, Health:3

6. ACIDENTAL RELEASE MEASURES

Personnel precautions: Appropriately trained personnel should respond to uncontrolled releases. Avoid direct contact with material; use the personal protective equipment specified in Section 8. Stay upwind of release; isolate the immediate hazard area; and keep unnecessary and unprotected people away. Use water spray to cool containers. Eliminate all sources of ignition. Provide explosion-proof clearing ventilation, if possible.
Environmental precautions: Prevent material from entering soil, waterways, drains, sewers, or confined areas.
Cleanup measures: Stop leak if safe to do so. Dyke and pump material into containers for recycling or disposal. Contact appropriate regulatory authorities for disposal requirements (see Section 13). Notify the appropriate regulatory authorities of reportable releases (see Section 15).

7. HANDLING AND STORAGE

Handling: Wear appropriate personal protective equipment. Avoid contact with liquid. Avoid inhalation. Bond and ground all transfers. Avoid sparking conditions. Wash hands and face after handling and before eating, drinking or smoking.
Storage: Store material in a cool, dry, well-ventilated area away from heat, strong sunlight, hot metal surfaces and ignition sources. Use approved containers only. Separate from incompatible material (see Section 10).

Caution: Hydrogen sulfide may accumulate in headspaces of tanks and other equipment, even when concentrations in the liquid product are low. Factors increasing this hazard potential include heating, agitation and contact of the liquid with acid or acid salts. Assess the exposure risk by gas monitoring. Wear air supplying breathing apparatus if necessary. Overexposure to hydrogen sulfide may cause dizziness, headache, nausea and possibly unconsciousness and death.

8. EXPOSURE CONTROL/PERSONAL PROTECTION

Occupational Exposure Limits

Hazardous Ingredients	Alberta OEL	Saskatchewan	OSHA PEL	ACGIH TLV
Petroleum Crude Oil	300 ppm; 500 ppm (15min)	300 ppm	--	--
Benzene	0.5 ppm; 2.5 ppm (15min), Skin	--	1 ppm; 5 STEL; Petroleum Industry: 10 ppm; 25 ppm (C)	0.5 ppm; 2.5 STEL, Skin
Hydrogen Sulfide	10 ppm; 15 ppm (C)	--	20 ppm (C)	1 ppm

Engineering Controls: Use only in well-ventilated areas. Local exhaust ventilation required in confined areas. Equipment must be explosion proof.
Hygiene Measures: Wash hands and face after handling and before eating, drinking or smoking. Take off contaminated clothing and wash before re-use.
Personal Protection
Respirator: Where concentrations may exceed exposure limits, use full-face, positive pressure self-contained breathing apparatus; full-face, positive pressure supplied-air breathing apparatus; or cartridge air-purifying respirator approved for organic vapours (note: cartridge respirator not suitable for hydrogen sulfide, oxygen deficienct or IDLH situations).
Gloves: Chemical-resistant gloves: Viton (Nitrile adequate for short exposure to liquid.)
Eyewear: Chemical splash goggles. A face shield may also be necessary, depending on handling conditions.
Footwear: As per safety policy.
Clothing: As per fire protection policy.

9. PHYSICAL AND CHEMICAL PROPERTIES

Physical State:	Liquid	**Odour & Appearance**:	Dark Brown, hydrocarbon-like
Odour Threshold (ppm):	Not Available	**Specific Gravity**:	0.7 – 0.8
Vapour Density (air=1):	2.5 -5.0 (estimated)	**Vapour Pressure (mmHg)**:	280-360 @ 20°C
Evaporation Rate:	Not Available	**Boiling Pt. (°C)**:	-40 to 530
Freezing Pt. (°C):	<-60	**pH**:	Not Available
Coefficient of Water/Oil Distribution:	<0.1	**Percent Volatiles, (v/v)**:	15 - 30 (estimated)

10. STABILITY AND REACTIVITY

Chemical Stability: Stable under normal, ambient conditions.
Incompatibility: Incompatible with strong oxidizing agents (e.g. chlorine, peroxide).
Reactivity: Reactive to heat, strong sunlight and ignition sources.
Hazardous Decomposition Products: Carbon monoxide, sulfur oxides, nitrogen oxides, smoke particles
Hazardous Polymerization: Not known to occur.

11. TOXICOLOGICAL INFORMATION

Acute Exposure
Vapour may cause irritation of eyes, nose and throat, dizziness and drowsiness. Contact with skin may cause irritation and possibly dermatitis. Contact of liquid with eyes may cause severe irritation or burns.

Hazardous Ingredients	Result	Species	Dose	Exposure
Petroleum Crude Oil	LD50 Oral LD50 Dermal LC50 Inhalation	Rat	>5 g/kg >2 g/kg >4300 ppm	-
Benzene	LD50 Oral LC50 Inhalation	Rat	0.9 g/kg 13200 ppm	- 4 hours
Hydrogen Sulfide	LC50 Inhalation	Rat	444 ppm	4 hours

Chronic Exposure
Due to presence of benzene, long term exposure may increase the risk of anemia and leukemia. Repeated skin contact may increase the risk of skin cancer.

Irritant: Yes
Skin Sensitization: Yes
Respiratory Sensitization: No
Carcinogenicity: Yes
Reproductive Toxicity: Possibly
Teratogenicity: Possibly
Mutagenicity: Possibly
Synergistic Materials/Products: None reported

Crude Oil
IARC – Crude oil is not classifiable as to its carcinogenicity to humans (Group 3).
ACGIH, OSHA, US NTP – not listed as a carcinogen.
Benzene
ACGIH A1-Confirmed Human Carcinogen
IARC, OSHA, US NTP – There is sufficient evidence that benzene is carcinogenic to man.
Hydrogen Sulfide
Hydrogen sulfide is not considered to be mutagenic or a reproductive or developmental toxicant.
ACGIH, IARC, OSHA, US NTP – Hydrogen sulfide is not listed as a carcinogen.

12. ECOLOGICAL INFORMATION

Aquatic Toxicity: Not available
Biodegradability: Not available

13. DISPOSAL CONSIDERATIONS

Waste Disposal: Contact appropriate regulatory authorities for disposal requirements. Empty containers or liners may retain a product residue. This material and its container and rinseates must be disposed of safely and in compliance with the requirements of environmental protection and waste disposal legislation and regional local authority requirements. Avoid dispersal of spilled material and runoff contact with soil, waterways, drains and sewers.
Use which results in chemical or physical change of this material could subject it to regulation as a hazardous product. Container residues and rinseates could be considered hazardous waste.

US EPA Waste Numbers
D001 – Ignitability characteristic
D018 – Toxicity characteristic (Benzene) (Regulatory Level = 0.5 mg/L)

14. TRANSPORT INFORMATION

Regulatory Information	UN Number	Proper Shipping Name	Class	PG	Label	Additional Information
TDG	UN1267	Petroleum Crude Oil	3	I	Flammable Liquids	
DOT	UN1267	Petroleum Crude Oil	3	I	Flammable Liquid	49 CFR 173.150; 173.202; 173.242
IMDG	UN1267	Petroleum Crude Oil	3	I	Flammable Liquid	12°C, P001 EmS:F-E, S-E MARPOL Annex I
ICAO/IATA	UN1267	Petroleum Crude Oil	3	I	Flammable Liquid	ERG Code: 3L

North American Emergency Response Guide Number: 128

15. REGULATORY INFORMATION

Canadian Classification

This product has been classified in accordance with the hazard criteria of the Controlled Products Regulation (CPR) and the MSDS contains all of the information required by the CPR.

WHMIS Classification: B2 – Flammable and combustible material – Flammable liquid
D2A – Poisonous and infectious material – Other effects – Very toxic
D2B – Poisonous and infectious material – Other effects – Toxic

WHMIS Ingredient Disclosure List:

Meets criteria for disclosure at 0.1% or greater of benzene.

CEPA Domestic Substance List: All components are either listed or exempt.

US Federal and State Regulations

The contents of this MSDS comply with the OSHA Hazard Communication Standard 29 CFR 1910.1200.

CERCLA/SARA – Section 302 Extremely Hazardous Substances: Exempt.

CERCLA/SARA 311-312 (Title III Hazard Categories):

Hydrogen Sulfide – Fire, Immediate (Acute),

Produced Hydrocarbons – Fire, Sudden Release of Pressure, Immediate (Acute), Delayed (Chronic).

CERCLA/SARA 313, Reportable Quantity: Benzene: 10 lbs; RCRA Code U019.

Clean Air Act Section 112(b) Hazardous Air Pollutants: Exempt.

United States National Chemical Inventory: All components are listed or exempted.

California 65: This product contains benzene a chemical known to the State of California to cause cancer and developmental harm.

16. OTHER INFORMATION

Guide to Abbreviations: ACGIH = American Conference of Governmental Hygienists; C = Ceiling; CAS = Chemical Abstracts Service Registry; Cenovus = Supplier recommendation based on composition; CEPA = Canadian Environmental Protection Act; DOT = Department of Transport; EmS = Environmental Management System; ERG = Emergency Response Guide
IARC = International Agency for Research on Cancer; ICAO/IATA = International Civil Aviation Organization/International Air Transport Association; IMDG = International Marine Dangerous Goods; MARPOL = The International Convention for the Prevention of Pollution from Ships; OEL = Occupational Exposure Limit; OSHA = Occupational Safety and Health Administration; PEL = Permissible Exposure Limit; PG = Packing Group; Skin = Danger of skin absorption; SARA STEL = Short Term Exposure Limit; TDG = Transportation of Dangerous Goods; TLV = Threshold Limit Value; US NTP = United States National Toxicology Program; v/v = volume per volume; WHMIS = Workplace Hazardous Materials Information System

Staff-Recommended CEQA Thresholds of Significance

This table revises and updates the proposed significance thresholds in the draft September 2009 CEQA Guidelines

POLLUTANT	STAFF RECOMMENDED CONSTRUCTION-RELATED	EXISTING CONSTRUCTION-RELATED	STAFF RECOMMENDED OPERATIONAL-RELATED		EXISTING OPERATIONAL-RELATED	
Project - Level						
Criteria Air Pollutants and Precursors (Regional)	**Maximum Daily Emissions (lb/day)**		**Maximum Daily Emissions (lb/day)**	**Annual Emissions (tpy)**	**Maximum Daily Emissions (lb/day)**	**Annual Emissions (tpy)**
ROG (reactive organic gases)	54	None	54	10	80	15
NOx (nitrogen oxides)	54	None	54	10	80	15
PM_{10} (particulate matter exhaust)	82	None	82	15	80	15
$PM_{2.5}$(particulate matter exhaust)	54	None	54	10	None	None
Fugitive Dust	Best Management Practices	Same	54	10	None	None
Criteria Air Pollutants and Precursors (Local CO)	None	None	9.0 ppm (8-hour average), 20.0 ppm (1-hour average)		Same	
GHGs – Projects other than Stationary Sources	None	None	Compliance with Qualified Climate Action Plan OR Threshold of 1,100 MT of CO_2e/yr OR 6.7 MT CO2e/capita/yr (residential) 4.6 MT CO_2e/SP/yr (mixed use)		None	
GHGs –Stationary Sources	None	None	10,000 MT/yr		None	
Risks and Hazards – Siting a New Source or Receptor	Cancer Risk > 10 in a million Non-Cancer Hazard Index >1.0 $PM_{2.5}$ level > 0.3 µg/m³ annual average	None	Compliance with Qualified Local Community Risk Reduction Plan OR Cancer Risk >10 in a million and Non-Cancer Hazard Index >1.0 and $PM_{2.5}$ level > 0.3 µg/m³ annual average <u>Zone of Influence</u>: 1,000 foot radius from fence line of source or receptor		Cancer Risk > 10 in a million Non-Cancer Hazard Index > 1.0	

(Revised 10-7-2009)

POLLUTANT	STAFF RECOMMENDED CONSTRUCTION-RELATED	EXISTING CONSTRUCTION-RELATED	STAFF RECOMMENDED OPERATIONAL-RELATED	EXISTING OPERATIONAL-RELATED
Risks and Hazards – Cumulative Significance Criteria (Source or Receptor)	Cancer Risk > 100 in a million Non-Cancer Hazard Index > 1.0 $PM_{2.5}$ level > 0.8 µg/m³ annual average Zone of Influence: 1,000 foot radius from fence line of source or receptor	None	Compliance with Qualified Local Community Risk Reduction Plan OR Cancer Risk > 100 in a million and Non-cancer Hazard Index > 1.0 and $PM_{2.5}$ level > 0.8 µg/m³ annual average Zone of Influence: 1,000 foot radius from fence line of source or receptor	None
Odors	None	None	Screening Level Distances and Complaint History	Screening Level Distances and Complaint History
Plan Level				
Criteria Air Pollutants and Precursors (Regional and Local)	None	None	Consistency with Current Air Quality Plan control measures AND Rate of VMT increase or vehicle trips is less than the rate of increase in the Plan's population growth rate	The jurisdiction's rate of VMT increase is equal or lower than the population growth rate assumed in the Clean Air Plan's emission inventory
GHGs	None	None	Qualified Climate Action Plan - emissions inventory - reduction goal consistent with AB32 - implementation measures - monitoring OR 6.7 MT CO2e/capita/yr (residential) 4.6 MT CO_2e/SP/yr (mixed use)	None
Risks and Hazards/Odors	None	None	Special Overlay zones around: • existing or planned sources of TACs and odors; • Community Risk Reduction Plan areas • 500 feet on each side of all freeways and high volume roadways.	None

Notes: CEQA = California Environmental Quality Act; CO = carbon monoxide; CO_2e = carbon dioxide equivalent; GHGs = greenhouse gases; lb/day = pounds per day; MT = metric tons; NO_x = oxides of nitrogen; $PM_{2.5}$= fine particulate matter with an aerodynamic resistance diameter of 2.5 micrometers or less; PM_{10} = respirable particulate matter with an aerodynamic resistance diameter of 10 micrometers or less; ppm = parts per million; ROG = reactive organic gases; SO_2 = sulfur dioxide; SP = service population; TACs = toxic air contaminants; TBP = toxic best practices; tons/day = tons per day; tpy = tons per year; yr= year; TBD: to be determined.

(Revised 10-7-2009)

Material Safety Data Sheets

The Material Safety Data Sheets (MSDS) provide descriptions for the safe handling of products that Cenovus produces, as well as any potential related health and safety hazards.

Bitumen Emulsion	Light Crude Oil (Bakken Oil)	
Condensate (Sour)	Natural Gas (Sour)	
Condensate (Sweet)	Natural Gas (Sweet)	
Crude Oil (Sour)	Natural Gas (Liquids)	
Crude Oil (Sweet)	Produced Water (Sour)	
Diluent (Offshore)	Produced Water (Sweet - from Shallow Gas Production)	
Heavy Crude Oil/Diluent Mix	Produced Water (Sweet - from Crude Oil or Deep Gas Production)	

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Condensate
Density (kg/m^3): 675 - 761
Gravity (°API): 54 - 79

MSW Feeder
Density (kg/m^3): 817 - 850
Gravity (°API): 34 - 42

Light Sour
Density (kg/m^3): 822 - 854
Gravity (°API): 34 - 41

Light Sweet
Density (kg/m^3): 828 - 830
Gravity (°API): 39 - 40

Sweet Synthetic
Density (kg/m^3): 835 - 866
Gravity (°API): 31 - 38

Medium Sour
Density (kg/m^3): 847 - 877
Gravity (°API): 29 - 36

Heavy Sour - Conventional
Density (kg/m^3): 914 - 935
Gravity (°API): 19 - 24

Heavy Sour - Unconventional
Density (kg/m^3): 923 - 929
Gravity (°API): 20 - 22

Heavy Sour - Synbit
Density (kg/m^3): 926 - 937
Gravity (°API): 19 - 21

Heavy Low Resid
Density (kg/m^3): 935 - 936
Gravity (°API): 19 - 20

Heavy Sour - Dilsynbit
Density (kg/m^3): 938 - 939
Gravity (°API): 19 - 20

Welcome to the new home of crudemonitor.ca

The website has been updated to improve ease of use and to better represent the available data for each given crude stream. All available data and reports for each crude have been represented on a crude data page, thus allowing for easy, one-stop access to the relevant information. The main sections have been listed below, along with brief descriptions of the available content and materials.

Data Reports

The data report pages provide a summarized view of the current and historical data for a single crude stream. Also included on these pages are distillation results (both simulated and physical), trend charts for key characteristics, and a customizable export to excel function.

To access the data reports, click on the crudemonitor.ca home button and select crude using scroll-down links on the left-hand column.

Monthly Reports

The monthly report pages detail the summary comments for a single crude stream. Comments are arranged by sampling month, and are labeled according to sample date and batch number. Links for the individual sample data have been provided for each comment.

To access the monthly reports, click on the monthly reports link at the top of the home page and select crude using scroll-down links on the left-hand column. The monthly reports page can also be accessed through a link on each crude data page.

Tools

Various tools related to crude blending and crude comparisons have been provided for public use.

Library

All reports for samples taken prior to January 1, 2010 are included on the Library page. Standardized one-page batch reports are available for individual samples, and full monthly reports with summary comments are available as well.

Industry Resources

The industry resources page includes links to various related industry organizations, both from Canada and the United States.

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Condensate Blend (CRW)

What is Condensate Blend?

CRW is a fully blended aggregate of many light sweet feeder streams and only begins its existence in blend tanks in Edmonton, Alberta. CRW is a fully equalized crude stream, wherein above standard feeders are compensated by substandard feeders on a net zero basis. The CRW blend is nearly completely consumed within Alberta as a diluent in heavy crude blending.

Enbridge Condensate Quality Specifications

Enbridge Pipelines is in the process of communicating specifications and guidelines for CRW quality, quality measurement methods, and penalty/mitigation requirements for non-compliance. The most recent version of the specifications summary is available here. Contact Enbridge Pipelines directly for additional information regarding CRW quality requirements.

Most Recent Sample Comments: CRW-326, Apr 1, 2013

Last 6 Samples

Marginally increased density and viscosity as well as reduced RVP, mercaptans, and butanes were observed in the April sample of Condensate Blend. This sample of CRW also experienced an increased 'tail' (C20+).

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	735.9	721.6	717.8	717.1
Gravity *(^{o}API)*	60.6	64.5	65.5	65.7
Sulphur *(wt%)*	0.18	0.15	0.14	0.18
MCR *(wt%)*	0.39	0.34	0.31	0.27
Viscosity @ 7.5oC *(cSt)*	1.04	0.88	0.85	0.83
RVP *(kPa)*	62.9	76.9	78.3	76.3
Sediment *(ppmw)*	120	146	176	131
Olefins *(wt%)*	-	ND	ND	ND
Organo-Phosphorus *(ppmw)*	-	0.5	1.8	1.0
Oxygenates *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Composition Summary

View Full Analysis

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
iso-Butane	0.21	0.42	0.45	0.52
n-Butane	1.65	2.55	2.72	2.87
iso-Pentane	12.06	14.35	14.88	14.18
n-Pentane	13.18	15.03	15.50	14.90
Hexanes	15.00	16.02	16.18	16.48
C7 x C12	41.92	39.68	39.08	41.26
Total C12-	84.06	88.23	88.99	90.44
C13 x C30+	15.94	11.77	11.01	9.56

BTEX

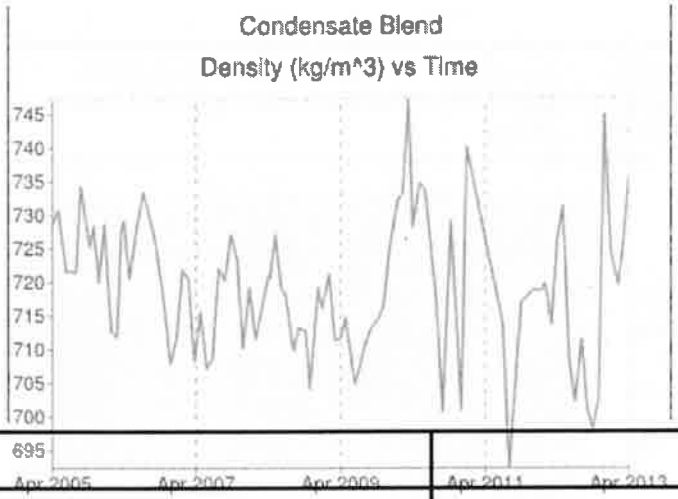
(Click for chart)

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.71	0.76	0.80	0.87
Toluene	1.31	1.48	1.49	1.58
Ethyl Benzene	0.26	0.19	0.19	0.20
Xylenes	1.23	1.27	1.24	1.30
BTEX Total	3.51	3.71	3.71	3.95

Trace Sulphur

Property *(mass ppm)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Volatile Mercaptans	31.1	38.5	38.0	59.5
C7- Mercaptans	39.1	62.1	62.2	90.2

Export Condensate Blend Data



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Fort Saskatchewan Condensate (CFT)

What is Fort Saskatchewan Condensate?

Fort Saskatchewan condensate is a fractionated stream produced by Keyera at their Fort Saskatchewan operations. CFT is delivered into CRW at the Enbridge Edmonton Terminal on a continuous, rateable basis.

Most Recent Sample Comments: CFT-190, Mar 1, 2013

Last 6 Samples

The March sample of Fort Saskatchewan Condensate was consistent with historical data. No oxygenates were detected.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	681.0	679.2	680.2	680.4
Gravity *(^{o}API)*	76.1	76.7	76.4	76.3
Sulphur *(wt%)*	0.04	0.04	0.04	0.04
MCR *(wt%)*	0.14	ND	ND	ND
Viscosity @ 7.5oC *(cSt)*	0.58	0.56	0.57	0.57
RVP *(kPa)*	92.4	92.1	83.1	83.1
Sediment *(ppmw)*	ND	20	32	35
Organo-Phosphorus *(ppmw)*	1.4	0.7	2.4	4.3
Oxygenates *(wt%)*	ND	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Composition Summary

View Full Analysis

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
iso-Butane	0.43	0.30	0.34	0.37
n-Butane	2.80	3.06	3.23	3.19
iso-Pentane	24.48	23.17	23.17	23.00
n-Pentane	23.94	22.79	22.55	22.50
Hexanes	19.08	19.08	19.00	19.00
C7 x C12	25.55	28.78	28.61	28.86
Total C12-	96.35	97.23	96.97	96.99
C13 x C30+	3.65	2.78	3.03	3.01

BTEX

(Click for chart)

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.68	0.85	0.84	0.84
Toluene	0.88	1.21	1.16	1.19
Ethyl Benzene	0.07	0.09	0.09	0.09
Xylenes	0.46	0.51	0.52	0.54
BTEX Total	2.09	2.65	2.60	2.66

Trace Sulphur

Property *(mass ppm)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Volatile Mercaptans	11.6	38.5	32.7	32.9
C7- Mercaptans	28.4	59.0	53.5	54.2

Export Fort Saskatchewan Condensate Data

Select all properties for export or select specific properties using adjacent checkboxes

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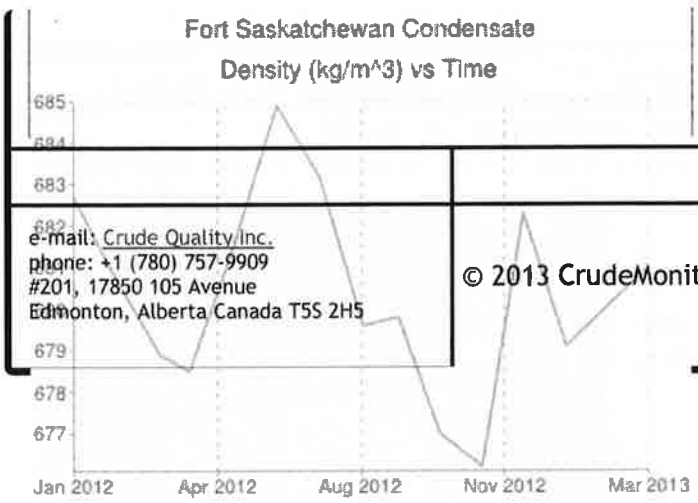

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Peace Condensate (CPR)

What is Peace Condensate?

Peace condensate is gathered from gas plant operations in the foothills to the northwest of Edmonton, and batch delivered to Edmonton on the Pembina Peace pipeline. CPR is blended into CRW at the Enbridge Edmonton Terminal on an intermittent basis dependent on batch arrivals.

Most Recent Sample Comments: CPR-381, Apr 1, 2013

Last 6 Samples

The April sample of Peace Condensate contained marginally reduced density, sulphur, MCR and sediment.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	744.5	755.0	756.6	755.8
Gravity *(°API)*	58.4	55.8	55.4	55.6
Sulphur *(wt%)*	0.14	0.19	0.23	0.22
MCR *(wt%)*	0.36	0.57	0.65	0.59
Viscosity @ 7.5oC *(cSt)*	1.30	1.42	1.43	1.37
RVP *(kPa)*	72.7	75.8	75.9	75.3
Sediment *(ppmw)*	111	271	299	294
Organo-Phosphorus *(ppmw)*	-	1.4	1.3	2.2
Oxygenates *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Composition Summary

View Full Analysis

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
iso-Butane	0.96	0.99	0.95	0.96
n-Butane	3.28	3.29	3.25	3.31
iso-Pentane	5.33	5.77	6.07	6.05
n-Pentane	6.71	6.96	7.35	7.35
Hexanes	11.39	11.03	11.10	11.27
C7 x C12	53.91	51.04	49.79	50.81
Total C12-	82.23	79.75	79.18	80.45
C13 x C30+	17.77	20.25	20.82	19.55

BTEX

(Click for chart)

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.90	0.70	0.70	0.73
Toluene	2.50	2.05	1.98	2.07
Ethyl Benzene	0.27	0.26	0.25	0.26
Xylenes	2.36	2.11	2.03	2.10
BTEX Total	6.03	5.12	4.97	5.16

Trace Sulphur

Property *(mass ppm)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Volatile Mercaptans	104.2	83.2	74.9	80.8
C7- Mercaptans	142.4	117.9	110.0	117.0

Export Peace Condensate Data

Select all properties for export or select specific properties using adjacent checkboxes

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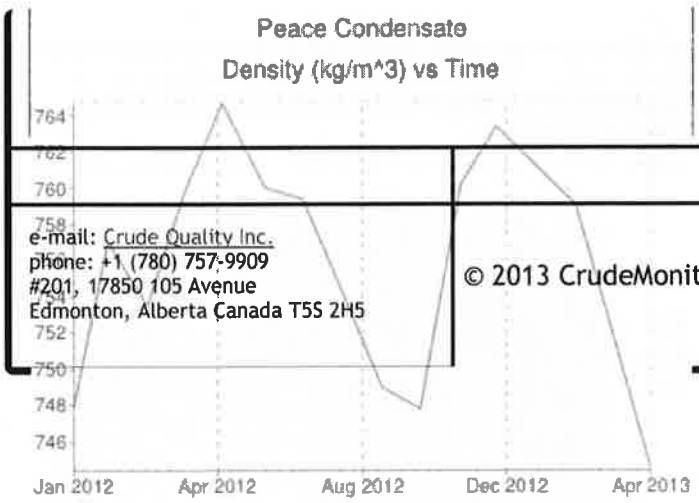

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Pembina Condensate (CPM)

What is Pembina Condensate?

Pembina condensate is gathered from gas plant operations in the foothills to the west of Edmonton, and batch delivered to Edmonton on the Pembina Drayton Valley pipeline. CPM is blended into CRW at the Enbridge Edmonton Terminal on an intermittent basis dependent on batch arrivals.

Most Recent Sample Comments: CPM-355, Mar 4, 2013

Last 6 Samples

Elevated density, MCR, viscosity, and RVP were observed in the March sample of Pembina Condensate while butanes were slightly decreased. Density and viscosity were marginally under upper limits defined by CRW specifications.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	772.1	769.1	762.1	761.0
Gravity *(°API)*	51.6	52.3	54.0	54.3
Sulphur *(wt%)*	0.11	0.12	0.11	0.11
MCR *(wt%)*	0.46	0.45	0.36	0.35
Viscosity @ 7.5oC *(cSt)*	1.77	1.69	1.49	1.45
RVP *(kPa)*	59.3	66.6	68.2	68.5
Sediment *(ppmw)*	91	64	109	119
Organo-Phosphorus *(ppmw)*	-	1.3	2.7	2.7
Oxygenates *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Composition Summary

View Full Analysis

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
iso-Butane	0.70	1.02	0.94	0.96
n-Butane	2.76	3.31	3.54	3.58
iso-Pentane	6.57	6.28	5.94	6.05
n-Pentane	6.87	6.82	6.54	6.66
Hexanes	10.44	10.77	10.67	10.73
C7 x C12	50.05	49.91	51.08	50.94
Total C12-	77.93	78.59	79.11	79.32
C13 x C30+	22.07	21.41	20.89	20.68

BTEX

(Click for chart)

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.80	0.82	0.86	0.87
Toluene	2.30	2.38	2.50	2.50
Ethyl Benzene	0.24	0.28	0.29	0.29
Xylenes	2.49	2.44	2.42	2.40
BTEX Total	5.83	5.93	6.06	6.06

Trace Sulphur

Property *(mass ppm)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Volatile Mercaptans	4.3	7.4	8.8	9.3
C7- Mercaptans	6.6	15.4	17.5	17.7

Export Pembina Condensate Data

Select all properties for export or select specific properties using adjacent checkboxes

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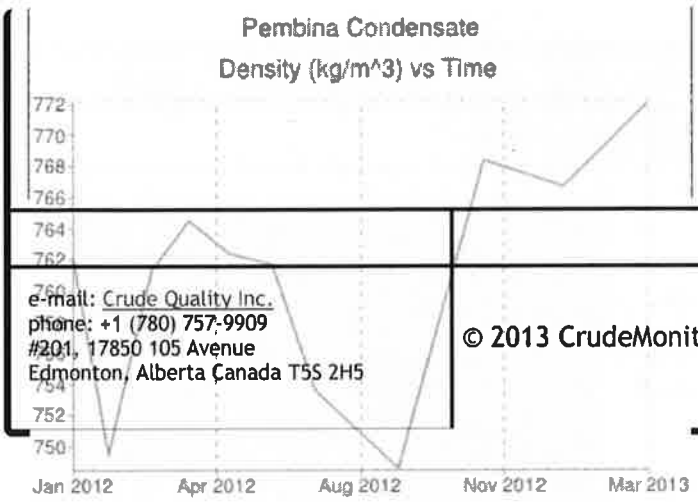

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Rangeland Condensate (CRL)

What is Rangeland Condensate?

Rangeland condensate is gathered from gas plant operations in the foothills to the southwest of Edmonton, and batch delivered to Edmonton on the Plains Midstream Marketing Rangeland pipeline. CRL is blended into CRW at the Enbridge Edmonton Terminal on an intermittent basis dependent on batch arrivals.

Most Recent Sample Comments: CRL-142, Apr 1, 2013

Last 6 Samples

Rangeland Condensate contained slightly reduced MCR, viscosity, and RVP for the month of April. Significant increases in BTEX and C7 x C9 content were also observed.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	756.4	757.4	760.3	760.2
Gravity *(^{o}API)*	55.4	55.2	54.5	54.5
Sulphur *(wt%)*	0.24	0.24	0.27	0.26
MCR *(wt%)*	0.34	0.50	0.72	0.73
Viscosity @ 7.5oC *(cSt)*	1.14	1.38	1.54	1.52
RVP *(kPa)*	60.1	69.7	70.5	71.1
Sediment *(ppmw)*	129	138	162	159
Organo-Phosphorus *(ppmw)*	-	ND	2.4	2.5
Oxygenates *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Composition Summary

View Full Analysis

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
iso-Butane	0.54	0.54	0.55	0.66
n-Butane	2.66	2.80	2.86	3.10
iso-Pentane	8.32	10.04	9.88	9.85
n-Pentane	8.29	9.74	9.75	9.68
Hexanes	12.81	12.81	12.76	12.86
C7 x C12	52.50	42.94	41.09	41.16
Total C12-	85.29	79.13	77.16	77.58
C13 x C30+	14.71	20.87	22.84	22.42

BTEX

(Click for chart)

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.78	0.79	0.79	0.80
Toluene	4.15	2.46	2.08	2.00
Ethyl Benzene	0.43	0.28	0.25	0.24
Xylenes	4.93	2.63	2.15	2.04
BTEX Total	10.29	6.15	5.26	5.08

Trace Sulphur

Property *(mass ppm)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Volatile Mercaptans	118.9	127.7	107.1	105.0
C7- Mercaptans	290.1	238.7	180.0	175.6

Export Rangeland Condensate Data

Select all properties for export or select specific properties using adjacent checkboxes

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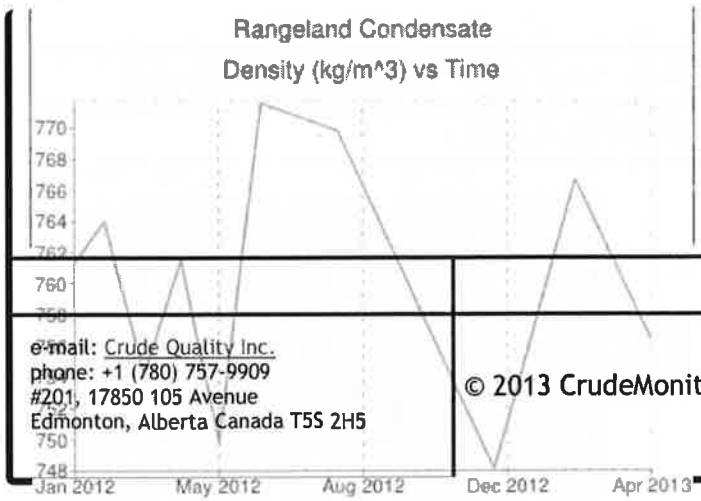

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Southern Lights Diluent (SLD)

What is Southern Lights Diluent?

Southern Lights condensate is a pentanes plus stream originating in the US midwest and transported to Edmonton, AB on the Enbridge Mainline system. It is delivered into CRW at the Edmonton Terminal on a continuous, rateable basis.

Most Recent Sample Comments: SLD-229, Mar 1, 2013

Last 6 Samples

BTEX and butanes were slightly increased while pentanes were decreased in the March sample of Southern Lights Diluent.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	679.7	675.9	674.0	675.1
Gravity *(^{o}API)*	76.5	77.7	78.3	77.9
Sulphur *(wt%)*	0.02	0.02	0.02	0.03
MCR *(wt%)*	ND	ND	ND	ND
Viscosity @ 7.5oC *(cSt)*	0.55	0.53	0.52	0.53
RVP *(kPa)*	80.1	83.8	82.5	81.3
Sediment *(ppmw)*	ND	ND	16	16
Organo-Phosphorus *(ppmw)*	-	5.4	5.4	7.1
Oxygenates *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Composition Summary

View Full Analysis

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
iso-Butane	0.11	0.07	0.06	0.06
n-Butane	2.76	1.90	1.67	1.58
iso-Pentane	21.22	21.85	22.90	22.61
n-Pentane	20.53	22.75	24.17	24.17
Hexanes	21.17	20.86	21.52	21.38
C7 x C12	32.42	31.39	28.61	28.76
Total C12-	98.23	98.83	98.95	98.59
C13 x C30+	0.00	0.22	0.26	0.79

BTEX

(Click for chart)

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.94	1.00	1.00	0.98
Toluene	1.37	1.11	1.04	1.04
Ethyl Benzene	0.10	0.10	0.10	0.11
Xylenes	0.88	0.52	0.47	0.48
BTEX Total	3.29	2.73	2.61	2.61

Trace Sulphur

Property *(mass ppm)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Volatile Mercaptans	10.1	11.0	16.4	18.7
C7- Mercaptans	43.6	55.4	50.1	50.9

Export Southern Lights Diluent Data

Select all properties for export or select specific properties using adjacent checkboxes

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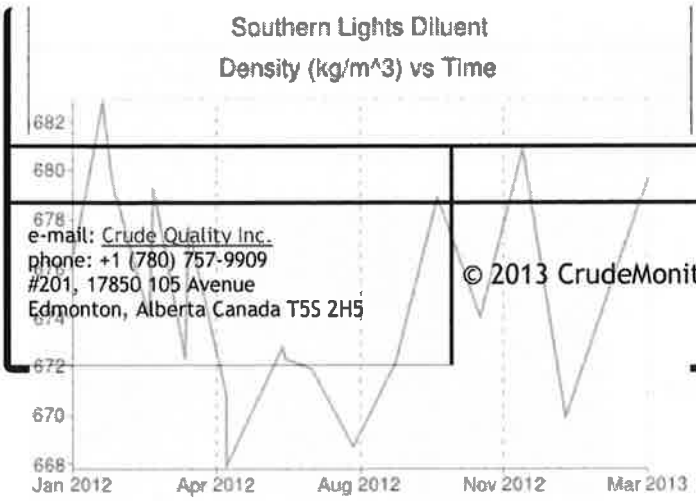

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Access Western Blend (AWB)

What is Access Western Blend crude?

Access Western Blend (AWB) is a heavy, high TAN dilbit produced by Devon Energy Canada and MEG Energy Corp. Production is from the Athabasca region south of Fort McMurray, Alberta. Production is generated by SAGD thermal methods. Diluent is supplied to the production sites from Edmonton and dilbit is pumped back to Edmonton on the Access Pipeline. AWB is available for upgrading in the Edmonton area, and for export on the Enbridge and Kinder Morgan systems.

Most Recent Sample Comments: AWB-831, Apr 14, 2013

Last 6 Samples

Apart from a slight increase in metals content, The April sample of Access Western Blend was consistent with historical averages. Simulated distillation results are included.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	917.5	920.5	923.0	922.1
Gravity *(°API)*	22.6	22.1	21.7	21.8
Sulphur *(wt%)*	3.89	3.88	3.89	3.93
MCR *(wt%)*	10.50	10.43	10.55	10.65
Sediment *(ppmw)*	100	89	157	201
TAN *(mgKOH/g)*	1.67	1.70	1.72	1.70
Salt *(ptb)*	5.1	7.1	6.6	6.8
Nickel *(mg/L)*	82.0	71.9	72.3	72.0
Vanadium *(mg/L)*	209.0	194.6	199.1	193.6
Olefins *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.02	0.03	0.04	0.03
Butanes	0.42	0.62	0.69	0.69
Pentanes	7.57	8.51	8.66	8.41
Hexanes	6.75	7.06	6.84	6.81
Heptanes	4.77	4.38	4.19	4.36
Octanes	2.83	2.40	2.25	2.57
Nonanes	1.53	1.21	1.12	1.25
Decanes	0.71	0.58	0.55	0.54

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.33	0.32	0.31	0.29
Toluene	0.61	0.52	0.50	0.50
Ethyl Benzene	0.07	0.05	0.05	0.06
Xylenes	0.45	0.38	0.36	0.39

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Access Western Blend Data

Select all properties for export or select specific properties using adjacent checkboxes

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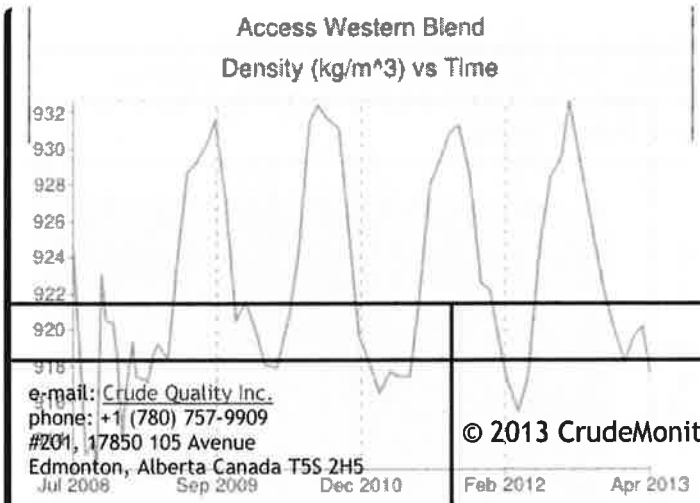

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Borealis Heavy Blend (BHB)

What is Borealis Heavy Blend crude?

Borealis Heavy Blend (BHB) is a Suncor Energy Canada diluted bitumen (dilbit) comprised of SAGD produced bitumen and hydrotreated naphtha/conventional diluent.

It is shipped from Fort McMurray to Edmonton and Hardisty, then to further markets across North America.

Most Recent Sample Comments: BHB-602, Apr 11, 2013

Last 6 Samples

Borealis Heavy Blend is a new crude stream for crudemonitor.ca. There is not enough data in our system at this point to comment on specific qualities or trends. Simulated distillation results are included.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	922.4	923.7	923.7	923.7
Gravity *(°API)*	21.8	21.6	21.6	21.6
Sulphur *(wt%)*	3.75	3.53	3.53	3.53
MCR *(wt%)*	10.20	9.07	9.07	9.07
Sediment *(ppmw)*	68	94	94	94
TAN *(mgKOH/g)*	2.44	2.21	2.21	2.21
Salt *(ptb)*	8.5	8.7	8.7	8.7
Nickel *(mg/L)*	63.0	55.3	55.3	55.3
Vanadium *(mg/L)*	168.0	151.3	151.3	151.3

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.00	0.00	0.00	0.00
Butanes	0.84	0.48	0.48	0.48
Pentanes	3.79	3.14	3.14	3.14
Hexanes	5.01	4.65	4.65	4.65
Heptanes	4.60	4.35	4.35	4.35
Octanes	6.16	5.59	5.59	5.59
Nonanes	4.97	4.48	4.48	4.48
Decanes	2.50	2.26	2.26	2.26

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.07	0.06	0.06	0.06
Toluene	0.31	0.28	0.28	0.28
Ethyl Benzene	0.17	0.16	0.16	0.16
Xylenes	0.61	0.59	0.59	0.59

Distillation

TBP	ASTM D2892 & D5236	No assays available for this crude.
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Borealis Heavy Blend Data

Select all properties for export or select specific properties using adjacent checkboxes

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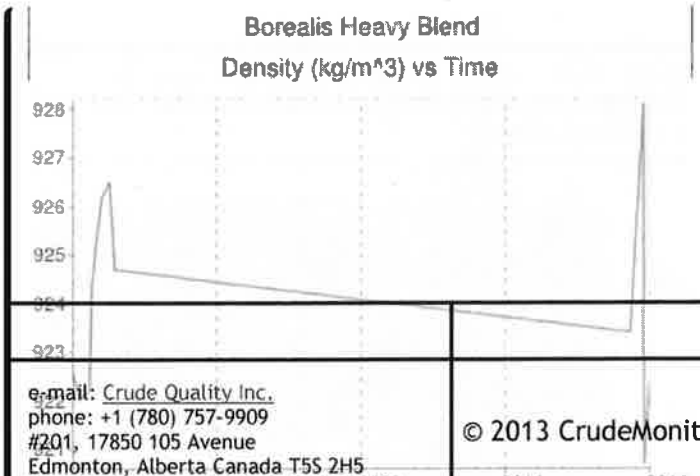

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Christina Dilbit Blend (CDB)

What is Christina Dilbit Blend crude?

Christina Dilbit Blend (CDB) is a diluted bitumen produced at the jointly owned Cenovus Energy Inc. and ConocoPhillips Christina Lake SAGD facility located about 120 km south of Fort McMurray. CDB is shipped on the Athabasca Pipeline to Hardisty area terminals where it has access to multiple downstream trunklines.

Most Recent Sample Comments: CDB-704, Apr 15, 2013

Last 6 Samples

Other than slightly elevated BTEX content, Christina Dilbit Blend was representative of historical data.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	918.2	922.0	925.4	923.1
Gravity *(^{o}API)*	22.5	21.9	21.3	21.7
Sulphur *(wt%)*	3.85	3.82	3.85	3.79
MCR *(wt%)*	10.30	10.10	10.11	10.12
Sediment *(ppmw)*	-	105	91	91
TAN *(mgKOH/g)*	1.59	1.55	1.59	1.54
Salt *(ptb)*	-	8.7	7.9	7.9
Nickel *(mg/L)*	71.0	65.9	66.8	66.9
Vanadium *(mg/L)*	189.0	180.7	178.7	176.5
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.02	0.04	0.03	0.04
Butanes	0.50	0.65	0.65	0.72
Pentanes	7.57	7.69	7.43	7.70
Hexanes	6.73	6.47	6.09	6.31
Heptanes	4.90	4.29	3.95	4.09
Octanes	2.82	2.57	2.29	2.45
Nonanes	1.35	1.32	1.15	1.25
Decanes	0.58	0.58	0.52	0.59

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.34	0.30	0.28	0.28
Toluene	0.64	0.51	0.47	0.47
Ethyl Benzene	0.07	0.06	0.05	0.06
Xylenes	0.47	0.38	0.34	0.36

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Christina Dilbit Blend Data

Select all properties for export or select specific properties using adjacent checkboxes

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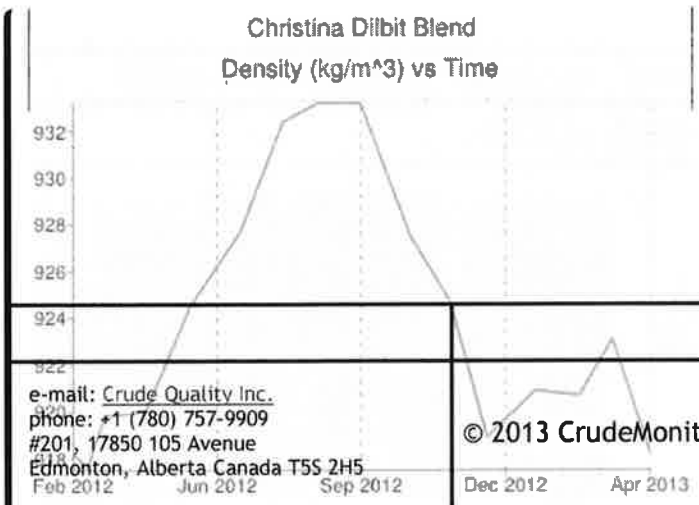

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Cold Lake (CL)

What is Cold Lake crude?

The main players in the Cold Lake oil sands deposit are Imperial Oil Resources, Cenovus Energy, Canadian Natural Resources Limited and Shell Energy. Cold Lake production is bitumen based and requires the use of steam to release the bitumen from the underground reservoirs, and the use of diluents to meet pipeline viscosity and density specifications.

Most Recent Sample Comments:
CL(E)-744, Apr 16, 2013

Last 6 Samples

The Edmonton sample of Cold Lake displayed increased BTEX and C7 x C10 content as well as reduced density, sulphur, and MCR.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	919.7	924.7	928.3	927.9
Gravity *(^{o}API)*	22.2	21.4	20.8	20.9
Sulphur *(wt%)*	3.63	3.75	3.77	3.79
MCR *(wt%)*	9.67	10.22	10.39	10.45
Sediment *(ppmw)*	-	96	91	162
TAN *(mgKOH/g)*	0.95	0.97	0.98	0.98
Salt *(ptb)*	-	10.6	10.4	11.8
Nickel *(mg/L)*	65.0	64.0	65.4	65.3
Vanadium *(mg/L)*	168.0	170.7	173.4	170.2
Olefins *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.04	0.04	0.04	0.04
Butanes	0.54	0.88	0.90	1.03
Pentanes	5.39	6.18	6.12	6.16
Hexanes	5.56	5.79	5.47	5.32
Heptanes	4.54	3.63	3.39	3.36
Octanes	3.36	2.40	2.16	2.23
Nonanes	2.68	1.52	1.38	1.36
Decanes	1.66	0.75	0.70	0.63

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.30	0.27	0.25	0.23
Toluene	0.67	0.45	0.41	0.39
Ethyl Benzene	0.11	0.06	0.06	0.06
Xylenes	0.62	0.38	0.33	0.33

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Cold Lake Data

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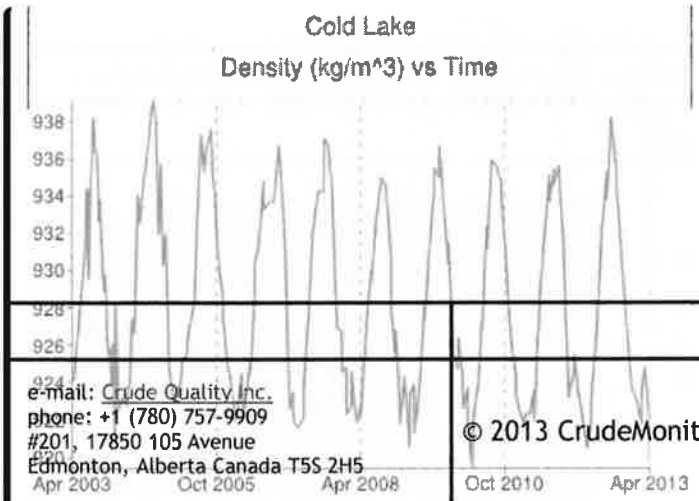

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Seal Heavy (SH)

What is Seal Heavy crude?

Seal Heavy is produced by Shell Energy Canada from the Peace River oilsands formation by conventional (cold flow, CHOPS) production methods. Seal Heavy is a heavy crude oil and bitumen blended with diluent to meet pipeline specifications for density and viscosity. Seal Heavy is delivered to Edmonton on the Rainbow Pipeline system.

Most Recent Sample Comments:
SH-622, Apr 13, 2013

Last 6 Samples

Density was slightly reduced while BTEX and C6 x C10 content was elevated for the April sample of Seal Heavy.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	923.8	928.4	930.4	930.5
Gravity *(°API)*	21.5	20.8	20.5	20.5
Sulphur *(wt%)*	4.63	4.68	4.69	4.71
MCR *(wt%)*	9.00	9.15	9.14	9.26
Sediment *(ppmw)*	-	190	183	169
TAN *(mgKOH/g)*	1.92	1.90	1.81	1.80
Salt *(ptb)*	-	20.4	19.0	21.8
Nickel *(mg/L)*	54.0	52.3	52.6	54.6
Vanadium *(mg/L)*	148.0	150.3	149.5	153.6
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.11	0.11	0.11	0.08
Butanes	1.44	1.46	1.44	1.48
Pentanes	4.17	3.73	3.47	4.34
Hexanes	5.01	4.68	4.41	4.47
Heptanes	5.04	4.60	4.37	3.89
Octanes	4.47	4.03	3.87	3.36
Nonanes	3.43	2.96	2.86	2.60
Decanes	1.61	1.41	1.35	1.14

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.27	0.26	0.25	0.21
Toluene	0.65	0.57	0.55	0.44
Ethyl Benzene	0.14	0.12	0.12	0.12
Xylenes	0.67	0.59	0.58	0.49

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Seal Heavy Data

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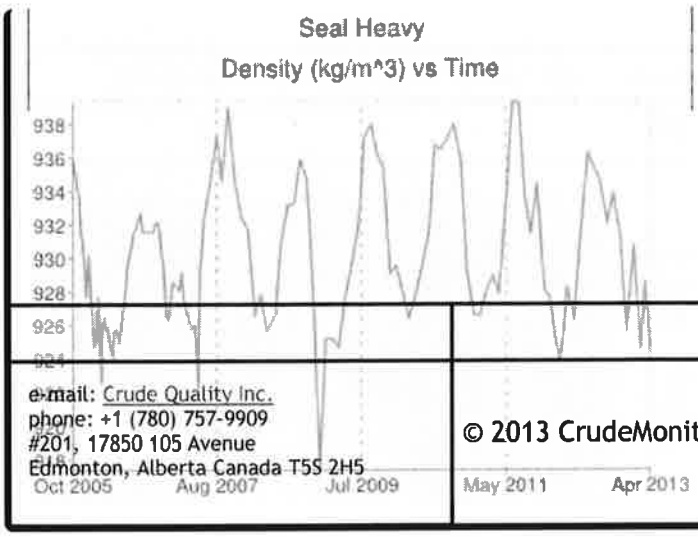

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Statoil Cheecham Blend (SCB)

What is Statoil Cheecham Blend crude?

Statoil's oil sands leases are located approximately 120 kilometres south of Fort McMurray in the Athabasca region of north east Alberta. The Leismer Demonstration Project (LDP) is being developed using SAGD (steam assisted gravity drainage) technology. LDP, approved to 10,000 barrels per day (bpd), is the first phase of the Leismer project, which is expected to ramp up to its rated capacity of 18,800 bpd within 24 months.

Most Recent Sample Comments: SCB-608, Jul 14, 2012

Last 6 Samples

Notable increases in benzene and toluene were observed in this sample of SCB. Slight increases were also observed in MCR and metals.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	930.4	925.5	928.8	928.8
Gravity *(°API)*	20.5	21.3	20.7	20.7
Sulphur *(wt%)*	3.86	3.77	3.81	3.81
MCR *(wt%)*	10.40	10.03	10.02	10.02
Sediment *(ppmw)*	-	87	169	169
TAN *(mgKOH/g)*	1.97	1.83	1.77	1.77
Salt *(ptb)*	-	4.6	5.3	5.3
Nickel *(mg/L)*	73.0	65.7	66.5	66.5
Vanadium *(mg/L)*	205.0	180.5	176.2	176.2
Olefins *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.02	0.01	0.01	0.01
Butanes	0.95	1.09	1.03	1.03
Pentanes	5.38	4.06	3.80	3.80
Hexanes	5.76	5.24	4.90	4.90
Heptanes	4.47	4.41	4.21	4.21
Octanes	3.52	4.80	4.79	4.79
Nonanes	2.19	3.56	3.60	3.60
Decanes	1.17	1.87	1.78	1.78

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.22	0.11	0.09	0.09
Toluene	0.51	0.34	0.31	0.31
Ethyl Benzene	0.09	0.13	0.13	0.13
Xylenes	0.50	0.51	0.53	0.53

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Statoil Cheecham Blend Data

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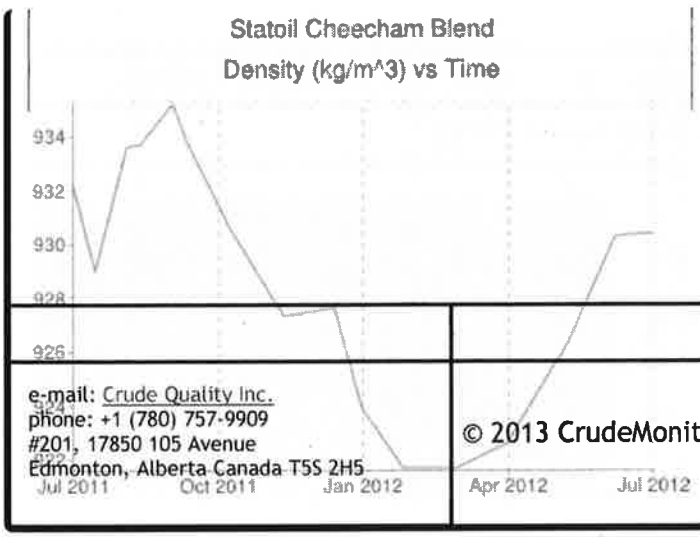

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Wabasca Heavy (WH)

What is Wabasca Heavy crude?

Wabasca Heavy is a blend of heavy oil production obtained by polymer injection and water flooding from the Athabasca region and typically has a 19-20 API gravity and 4.15 wt% sulphur content. Principal producers of the Wabasca Stream include Cenovus Energy and Canadian Natural Resources, though other producers do connect to the Wabasca Heavy stream. Wabasca Heavy is delivered to Edmonton via the Pembina Pipeline and Rainbow Pipelines.

Most Recent Sample Comments:
WH-769, Apr 14, 2013

Last 6 Samples

Notably high concentrations of C7 x C10 and BTEX were detected in the April sample Wabasca Heavy. Simulated distillation results are included.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density (kg/m^3)	930.2	932.3	934.7	932.1
Gravity (°API)	20.5	20.2	19.8	20.2
Sulphur (wt%)	4.10	4.09	4.13	4.14
MCR (wt%)	8.81	8.63	8.70	8.74
Sediment (ppmw)	66	115	107	160
TAN (mgKOH/g)	1.04	1.05	1.05	1.04
Salt (ptb)	8.0	9.1	9.6	14.6
Nickel (mg/L)	53.0	52.4	52.7	52.8
Vanadium (mg/L)	149.0	147.0	146.9	144.3
Olefins (wt%)	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property (vol%)	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.06	0.08	0.08	0.07
Butanes	1.39	1.60	1.65	1.72
Pentanes	1.49	1.84	1.73	2.71
Hexanes	2.99	3.05	2.85	3.06
Heptanes	4.33	3.60	3.35	2.93
Octanes	5.40	3.86	3.55	3.00
Nonanes	4.76	3.10	2.86	2.50
Decanes	2.45	1.48	1.38	1.13

BTEX

Property (vol%)	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.15	0.13	0.12	0.12
Toluene	0.54	0.40	0.37	0.29
Ethyl Benzene	0.23	0.15	0.15	0.13
Xylenes	0.92	0.61	0.58	0.47

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Wabasca Heavy Data

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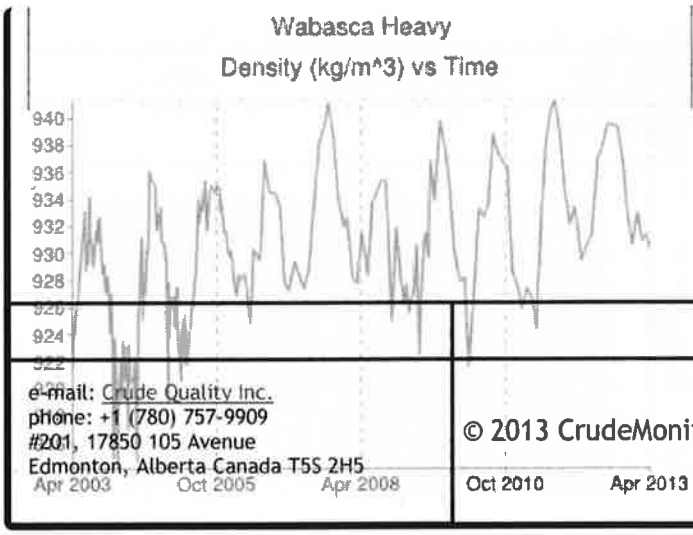

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Western Canadian Select (WCS)

What is Western Canadian Select crude?

Western Canadian Select is a Hardisty based blend of conventional and oilsands production managed by Canadian Natural Resources, Cenovus Energy, Suncor Energy, and Talisman Energy. Argus has launched daily volume-weighted average price indexes for Western Canadian Select (WCS) and will publish this index in the daily Argus Crude and Argus Americas Crude publications.

Most Recent Sample Comments: WCS-838, Apr 15, 2013

Last 6 Samples

Western Canadian Select continues to show elevated BTEX and C7 x C10 content for the April 15 sample.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	923.5	925.9	928.8	929.3
Gravity *(^{o}API)*	21.6	21.2	20.7	20.6
Sulphur *(wt%)*	3.39	3.48	3.50	3.50
MCR *(wt%)*	9.65	9.61	9.72	9.64
Sediment *(ppmw)*	-	297	276	331
TAN *(mgKOH/g)*	0.94	0.94	0.95	0.94
Salt *(ptb)*	-	33.8	37.4	48.0
Nickel *(mg/L)*	60.0	58.0	58.8	58.1
Vanadium *(mg/L)*	144.0	142.0	141.5	140.2
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.05	0.06	0.06	0.06
Butanes	1.41	1.86	1.85	2.02
Pentanes	4.36	4.86	4.72	4.30
Hexanes	4.38	4.40	4.17	3.88
Heptanes	3.72	3.11	2.92	2.79
Octanes	2.85	2.23	2.05	2.12
Nonanes	2.07	1.55	1.45	1.50
Decanes	1.01	0.78	0.76	0.72

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.22	0.19	0.18	0.16
Toluene	0.47	0.34	0.31	0.30
Ethyl Benzene	0.08	0.06	0.05	0.06
Xylenes	0.43	0.31	0.28	0.29

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Western Canadian Select Data

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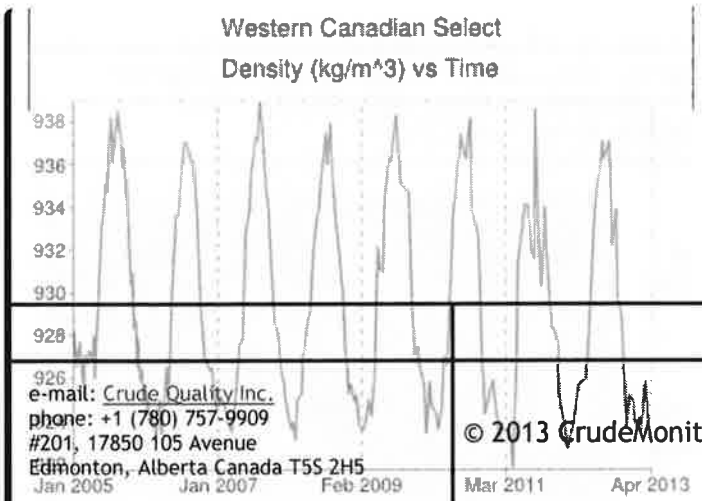

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Albian Heavy Synthetic (AHS)

What is Albian Heavy Synthetic crude?

Albian Heavy Synthetic (AHS) is a partially upgraded dilsynbit produced from the Scotford Upgrader. The Scotford Upgrader is part of the Athabasca Oil Sands Project (AOSP), a joint venture between Shell Canada Energy (operator and 60% owner), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%). AHS is a heavy crude oil, but due to partial upgrading, contains lower sulphur and TAN than unprocessed dilbits and synbits.

Most Recent Sample Comments: AHS-645, Apr 14, 2013

Last 6 Samples

The April sample of Albian Heavy Synthetic recorded a slightly reduced density.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	932.7	937.4	938.2	938.8
Gravity *(°API)*	20.1	19.3	19.2	19.1
Sulphur *(wt%)*	2.62	2.48	2.52	2.41
MCR *(wt%)*	12.30	12.84	12.32	12.17
Sediment *(ppmw)*	-	828	603	743
TAN *(mgKOH/g)*	0.60	0.49	0.55	0.50
Salt *(ptb)*	-	12.0	11.4	12.5
Nickel *(mg/L)*	55.0	46.1	44.2	44.0
Vanadium *(mg/L)*	112.0	90.7	88.7	86.5
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.24	0.14	0.10	0.12
Butanes	1.63	1.45	1.36	1.50
Pentanes	4.90	5.17	5.40	4.58
Hexanes	5.79	5.53	5.34	5.06
Heptanes	4.33	3.94	3.60	3.81
Octanes	4.11	3.57	3.09	3.31
Nonanes	2.78	2.36	2.03	2.09
Decanes	1.31	1.10	0.98	0.94

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.14	0.14	0.14	0.15
Toluene	0.36	0.32	0.30	0.38
Ethyl Benzene	0.15	0.12	0.10	0.12
Xylenes	0.44	0.40	0.34	0.44

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Albian Heavy Synthetic Data

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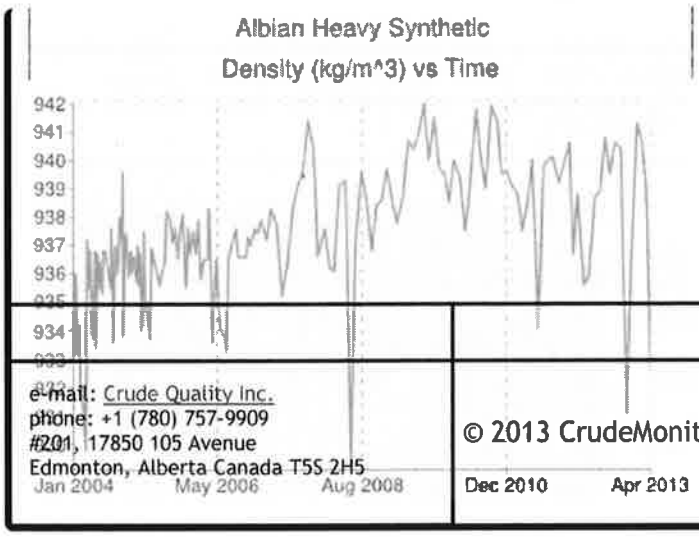

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CNRL Light Sweet Synthetic (CNS)

What is CNRL Light Sweet Synthetic crude?

CNS is a light sweet synthetic crude produced from the Canadian Natural Resources Ltd Horizon Project located north of Fort McMurray, Alberta. The Horizon Project includes a mine and upgrader operations. It is a classic bottomless blend of hydrotreated naphtha, distillate, and gasoil fractions produced from a coker based upgrader facility.

Most Recent Sample Comments:
CNS-953, Apr 1, 2013

Last 6 Samples

The April sample of CNRL Light Sweet Synthetic contained typical light ends and bulk properties. Simulated distillation results are included.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	851.7	850.6	851.1	850.3
Gravity *(^{o}API)*	34.5	34.7	34.6	34.8
Sulphur *(wt%)*	0.09	0.09	0.09	0.07
MCR *(wt%)*	ND	ND	ND	ND
Nickel *(mg/L)*	ND	ND	ND	ND
Vanadium *(mg/L)*	ND	ND	ND	ND
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.02	0.01	0.01	0.01
Butanes	1.09	1.15	1.11	1.16
Pentanes	2.55	2.63	2.59	2.61
Hexanes	3.67	3.67	3.57	3.45
Heptanes	3.70	3.66	3.57	3.39
Octanes	5.16	5.24	5.23	4.96
Nonanes	5.08	4.86	4.88	4.73
Decanes	2.65	2.68	2.72	2.55

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.05	0.04	0.04	0.04
Toluene	0.25	0.24	0.23	0.21
Ethyl Benzene	0.18	0.17	0.18	0.17
Xylenes	0.59	0.61	0.60	0.57

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export CNRL Light Sweet Synthetic Data

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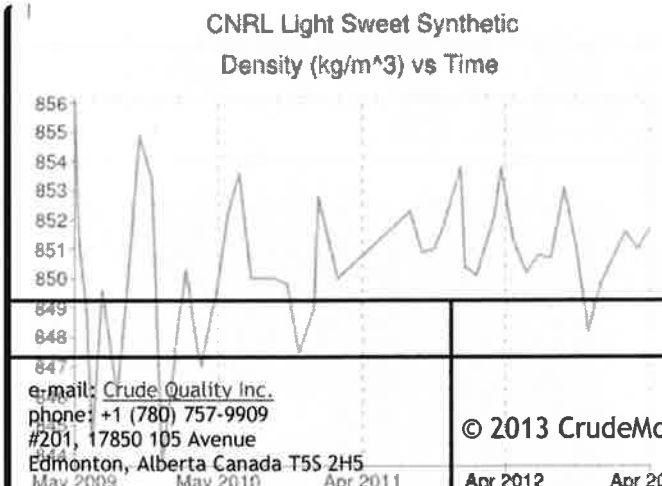

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Husky Synthetic Blend (HSB)

What is Husky Synthetic Blend crude?

Husky Synthetic Blend is an upgraded, bottomless sweet synthetic crude.

Most Recent Sample Comments: HSB-978, Apr 16, 2013

Last 6 Samples

Apart from a slightly elevated density, Husky Synthetic Blend was comparable to historic data for the month of April. Simulated distillation results are included.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	868.1	868.3	868.0	863.7
Gravity *(^{o}API)*	31.4	31.3	31.4	32.2
Sulphur *(wt%)*	0.10	0.10	0.10	0.10
MCR *(wt%)*	0.10	ND	ND	ND
Nickel *(mg/L)*	ND	ND	ND	ND
Vanadium *(mg/L)*	ND	0.3	0.2	ND
Olefins *(wt%)*	-	0.6	0.6	0.5

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.17	0.16	0.18	0.17
Butanes	1.21	1.02	1.28	2.39
Pentanes	1.70	1.66	1.68	1.60
Hexanes	2.15	2.13	2.07	2.00
Heptanes	2.18	2.18	2.11	2.02
Octanes	2.95	2.95	2.86	2.71
Nonanes	2.60	2.48	2.44	2.42
Decanes	1.28	1.28	1.30	1.28

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.03	0.04	0.04	0.04
Toluene	0.16	0.16	0.15	0.15
Ethyl Benzene	0.11	0.10	0.10	0.10
Xylenes	0.34	0.35	0.34	0.33

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Husky Synthetic Blend Data

Select all properties for export or select specific properties using adjacent checkboxes

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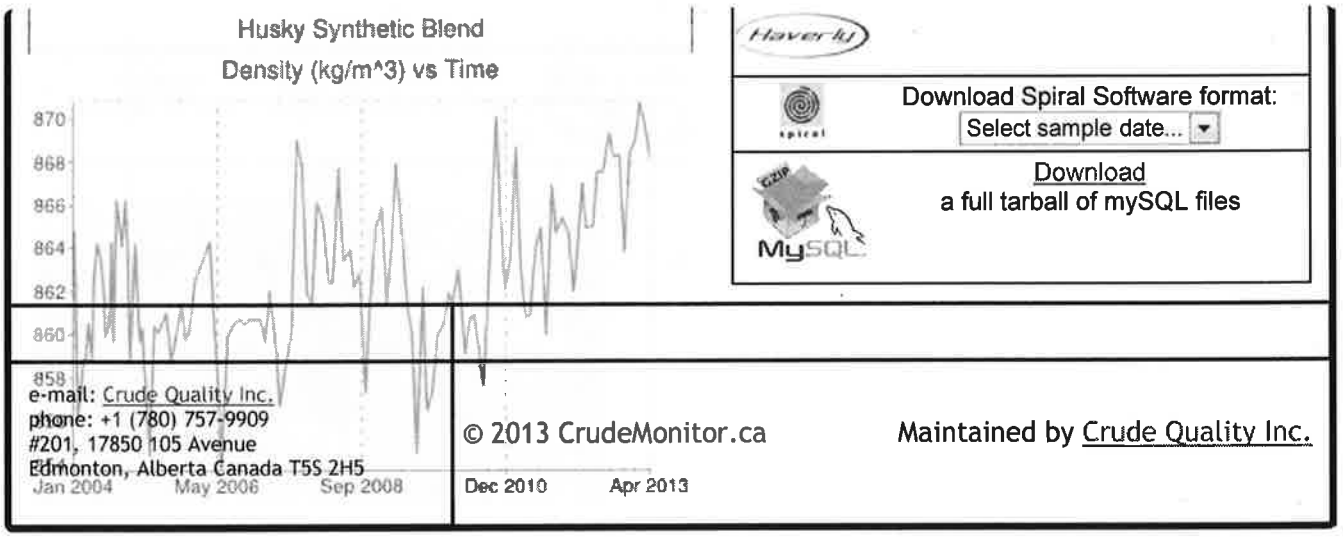
Husky Synthetic Blend
Density (kg/m^3) vs Time
870
868
866
864
862
860
858
Jan 2004
May 2006
Sep 2008
Dec 2010
Apr 2013
Haverly
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Long Lake Light Synthetic (PSC)

What is Long Lake Light Synthetic crude?

Long Lake Light Synthetic is a light sweet synthetic crude produced from the Nexen/OPTI Long Lake Upgrader immediately southeast of Fort McMurray, Alberta. All bitumen fed to the upgrader is produced from SAGD operations. PSC is a classic bottomless blend of hydrotreated naphtha, distillate and gasoil produced from a hydrocracker based upgrader facility.

Most Recent Sample Comments:
PSC-808, Apr 15, 2013

Last 6 Samples

Slightly reduced density as well as elevated BTEX and C6 x C10 concentrations were observed in the April sample of Long Lake Light Synthetic.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	814.0	829.6	830.9	839.0
Gravity *(^{o}API)*	42.2	39.0	38.7	37.1
Sulphur *(wt%)*	0.09	0.10	0.10	0.08
MCR *(wt%)*	0.10	ND	ND	ND
TAN *(mgKOH/g)*	-	-	-	ND
Nickel *(mg/L)*	ND	0.3	0.2	0.1
Vanadium *(mg/L)*	2.0	2.2	1.7	1.0
Olefins *(wt%)*	-	-	-	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.00	0.02	0.02	0.02
Butanes	1.67	1.08	1.53	1.17
Pentanes	3.00	2.39	2.59	2.39
Hexanes	5.15	4.28	4.32	3.94
Heptanes	6.87	5.62	5.43	4.75
Octanes	9.82	8.07	7.64	6.41
Nonanes	8.26	6.73	6.35	5.41
Decanes	3.53	3.06	2.89	2.37

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.25	0.18	0.17	0.15
Toluene	0.65	0.50	0.49	0.43
Ethyl Benzene	0.33	0.26	0.25	0.21
Xylenes	1.11	0.86	0.83	0.69

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Long Lake Light Synthetic Data

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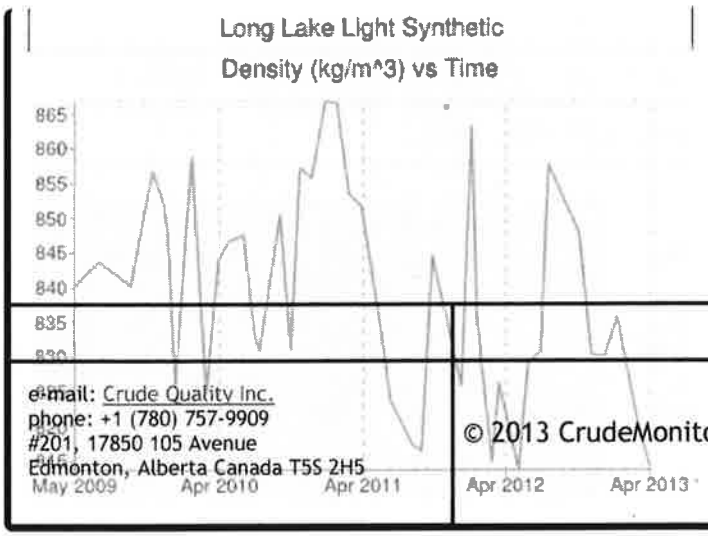

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Shell Synthetic Light (SSX)

What is Shell Synthetic Light crude?

Shell Synthetic Light (SSX) is a light sweet synthetic crude produced from Shell Canada□s Scotford complex. SSX is a classic bottomless synthetic blend of hydrotreated naphtha, distillate, and gasoil. SSX yield is heavily weighted in hydrotreated gasoil, and is generally used to fill refinery catalytic cracker or hydrocracker capacity. SSX is produced exclusively from hydrogen addition processes (hydrotreating and hydrocracking).

Most Recent Sample Comments: SSX-645, Apr 20, 2013

Last 6 Samples

Marginally elevated hexanes and reduced butanes were detected in the April sample of Shell Synthetic Light.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	860.2	861.9	864.5	860.1
Gravity *(°API)*	32.8	32.5	32.1	32.9
Sulphur *(wt%)*	0.13	0.15	0.15	0.11
MCR *(wt%)*	ND	ND	ND	0.11
Nickel *(mg/L)*	ND	ND	ND	ND
Vanadium *(mg/L)*	ND	ND	ND	0.1
Olefins *(wt%)*	-	-	-	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.02	0.06	0.05	0.06
Butanes	0.13	0.82	1.11	0.79
Pentanes	2.91	4.31	3.79	2.01
Hexanes	5.81	4.60	3.96	3.97
Heptanes	5.27	3.57	3.13	4.20
Octanes	5.43	3.28	3.02	4.73
Nonanes	2.64	2.04	2.02	2.59
Decanes	0.72	0.81	0.96	0.93

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.13	0.12	0.12	0.15
Toluene	0.47	0.30	0.28	0.46
Ethyl Benzene	0.19	0.11	0.11	0.18
Xylenes	0.63	0.37	0.37	0.62

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Shell Synthetic Light Data

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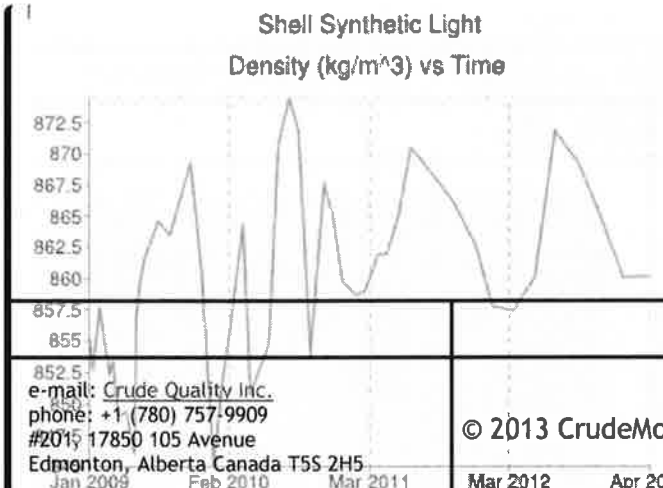

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Suncor Synthetic A (OSA)

What is Suncor Synthetic A crude?

OSA is a light sweet synthetic crude produced from the Suncor Canada Project located north of Fort McMurray, Alberta. The Suncor facilities includes a mine, SAGD and upgrader operations. OSA is a classic bottomless blend of hydrotreated naphtha, distillate, and gasoil fractions produced from a coker based upgrader facility. The Suncor project came on stream in 1967 and became the world's first oil sands operation.

Most Recent Sample Comments: OSA-633, Apr 3, 2013

Last 6 Samples

Suncor Synthetic A contained typical light ends and bulk properties.

Monthly Reports

Basic Analysis

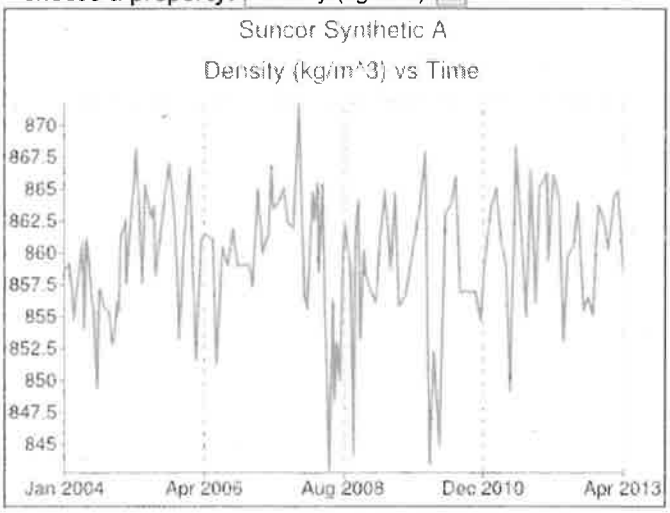
Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	858.4	861.4	860.0	858.3
Gravity *(°API)*	33.2	32.6	32.9	33.2
Sulphur *(wt%)*	0.17	0.18	0.18	0.18
MCR *(wt%)*	ND	ND	ND	ND
Nickel *(mg/L)*	ND	ND	ND	ND
Vanadium *(mg/L)*	ND	ND	ND	ND
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)



Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.00	0.00	0.01	0.02
Butanes	1.24	1.51	1.64	1.71
Pentanes	4.00	3.28	3.32	3.07
Hexanes	4.00	3.75	4.00	4.07
Heptanes	3.32	3.15	3.33	3.52
Octanes	4.20	3.99	4.03	4.43
Nonanes	3.90	3.45	3.45	3.75
Decanes	2.19	1.92	1.97	2.02

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.08	0.04	0.05	0.05
Toluene	0.26	0.20	0.21	0.23
Ethyl Benzene	0.14	0.12	0.12	0.14
Xylenes	0.53	0.45	0.46	0.51

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Suncor Synthetic A Data

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Syncrude Synthetic (SYN)

What is Syncrude Synthetic crude?

Syncrude Synthetic is a light sweet synthetic crude produced from the Syncrude Canada Project located north of Fort McMurray, Alberta. The Syncrude Project includes a mine and upgrader operations. It is a classic bottomless blend of hydrotreated naphtha, distillate, and gasoil fractions produced from a coker and hydrocracker based upgrader facility. In 1973, construction began on the Syncrude site and, after five years of construction, the first barrel was shipped on July 30, 1978.

Most Recent Sample Comments:
SYN-786, Apr 1, 2013

Last 6 Samples

Marginally reduced concentrations in the C4 x C8 range as well as a slightly elevated density were observed in the April sample of Syncrude Synthetic.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	870.6	863.4	861.0	863.2
Gravity *(^{o}API)*	30.9	32.2	32.7	32.3
Sulphur *(wt%)*	0.16	0.18	0.17	0.17
MCR *(wt%)*	ND	ND	ND	ND
Nickel *(mg/L)*	ND	ND	ND	ND
Vanadium *(mg/L)*	ND	ND	ND	ND
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.10	0.07	0.07	0.07
Butanes	1.25	2.00	2.16	2.01
Pentanes	1.69	2.18	2.43	2.46
Hexanes	2.90	3.47	3.78	3.79
Heptanes	2.91	3.39	3.61	3.51
Octanes	3.54	4.01	4.23	4.11
Nonanes	3.08	3.29	3.40	3.29
Decanes	1.53	1.72	1.78	1.66

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.16	0.18	0.19	0.19
Toluene	0.43	0.43	0.47	0.46
Ethyl Benzene	0.16	0.16	0.18	0.17
Xylenes	0.58	0.58	0.61	0.62

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

Export Syncrude Synthetic Data

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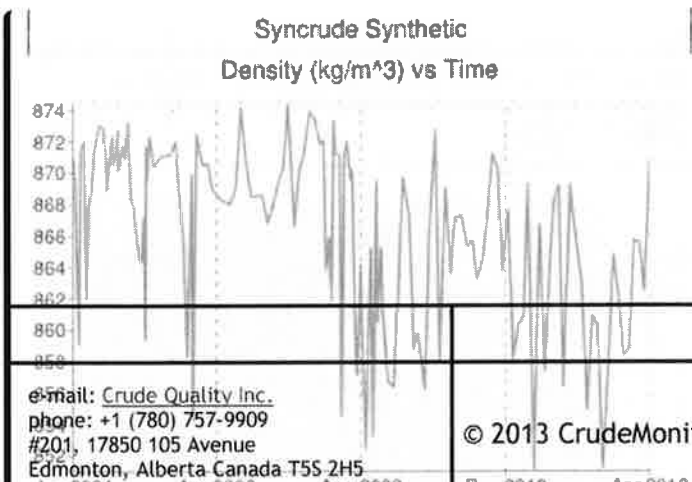

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Christina Dilbit Blend (CDB)

What is Christina Dilbit Blend crude?

Christina Dilbit Blend (CDB) is a diluted bitumen produced at the jointly owned Cenovus Energy Inc. and ConocoPhillips Christina Lake SAGD facility located about 120 km south of Fort McMurray. CDB is shipped on the Athabasca Pipeline to Hardisty area terminals where it has access to multiple downstream trunklines.

Most Recent Sample Comments:
CDB-704, Apr 15, 2013

Last 6 Samples

Other than slightly elevated BTEX content, Christina Dilbit Blend was representative of historical data.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density (kg/m^3)	918.2	922.0	925.4	923.1
Gravity (^{o}API)	22.5	21.9	21.3	21.7
Sulphur (wt%)	3.85	3.82	3.85	3.79
MCR (wt%)	10.30	10.10	10.11	10.12
Sediment (ppmw)	-	105	91	91
TAN (mgKOH/g)	1.59	1.55	1.59	1.54
Salt (ptb)	-	8.7	7.9	7.9
Nickel (mg/L)	71.0	65.9	66.8	66.9
Vanadium (mg/L)	189.0	180.7	178.7	176.5
Olefins (wt%)	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property (vol%)	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.02	0.04	0.03	0.04
Butanes	0.50	0.65	0.65	0.72
Pentanes	7.57	7.69	7.43	7.70
Hexanes	6.73	6.47	6.09	6.31
Heptanes	4.90	4.29	3.95	4.09
Octanes	2.82	2.57	2.29	2.45
Nonanes	1.35	1.32	1.15	1.25
Decanes	0.58	0.58	0.52	0.59

BTEX

Property (vol%)	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.34	0.30	0.28	0.28
Toluene	0.64	0.51	0.47	0.47
Ethyl Benzene	0.07	0.06	0.05	0.06
Xylenes	0.47	0.38	0.34	0.36

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample / Historical Average

Export Christina Dilbit Blend Data

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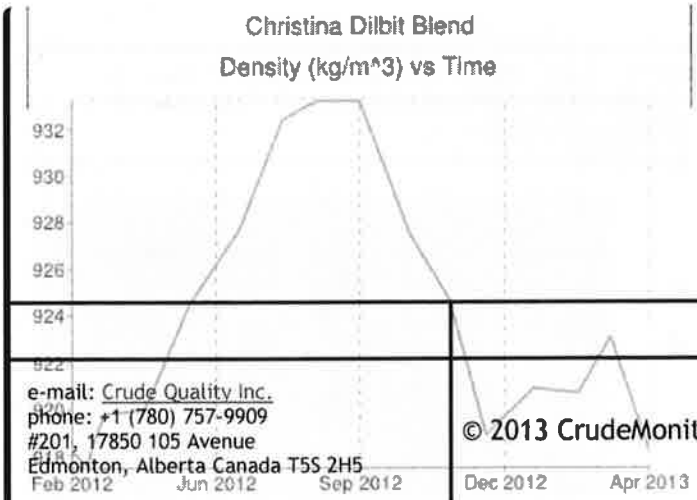

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Western Canadian Select (WCS)

What is Western Canadian Select crude?

Western Canadian Select is a Hardisty based blend of conventional and oilsands production managed by Canadian Natural Resources, Cenovus Energy, Suncor Energy, and Talisman Energy. Argus has launched daily volume-weighted average price indexes for Western Canadian Select (WCS) and will publish this index in the daily Argus Crude and Argus Americas Crude publications.

Most Recent Sample Comments: WCS-838, Apr 15, 2013

Last 6 Samples

Western Canadian Select continues to show elevated BTEX and C7 x C10 content for the April 15 sample.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	923.5	925.9	928.8	929.3
Gravity *(°API)*	21.6	21.2	20.7	20.6
Sulphur *(wt%)*	3.39	3.48	3.50	3.50
MCR *(wt%)*	9.65	9.61	9.72	9.64
Sediment *(ppmw)*	-	297	276	331
TAN *(mgKOH/g)*	0.94	0.94	0.95	0.94
Salt *(ptb)*	-	33.8	37.4	48.0
Nickel *(mg/L)*	60.0	58.0	58.8	58.1
Vanadium *(mg/L)*	144.0	142.0	141.5	140.2
Olefins *(wt%)*	-	-	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.05	0.06	0.06	0.06
Butanes	1.41	1.86	1.85	2.02
Pentanes	4.36	4.86	4.72	4.30
Hexanes	4.38	4.40	4.17	3.88
Heptanes	3.72	3.11	2.92	2.79
Octanes	2.85	2.23	2.05	2.12
Nonanes	2.07	1.55	1.45	1.50
Decanes	1.01	0.78	0.76	0.72

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.22	0.19	0.18	0.16
Toluene	0.47	0.34	0.31	0.30
Ethyl Benzene	0.08	0.06	0.05	0.06
Xylenes	0.43	0.31	0.28	0.29

Distillation

TBP	ASTM D2892 & D5236	Select an assay date...
HTSD	ASTM D7169	Most Recent Sample Historical Average

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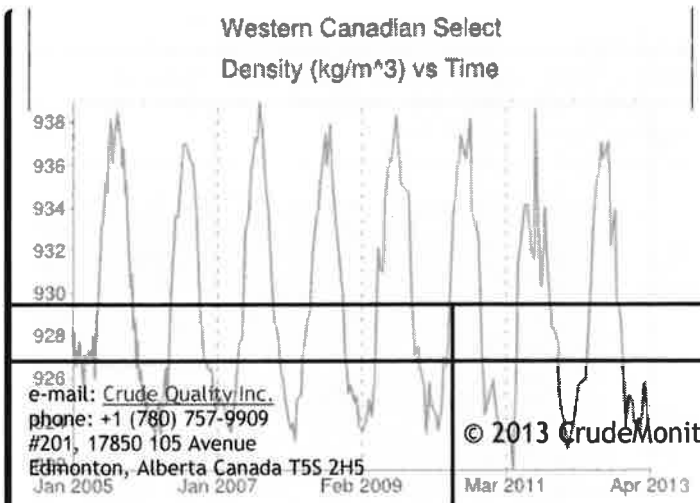

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Peace River Heavy (PH)

What is Peace River Heavy crude?

Peace Heavy is produced at Shell Energy Canada's Cadotte Lake thermal production complex near Peace River, Alberta. It uses enhanced oil recovery techniques to recover bitumen from underground reservoirs. Peace Heavy is a heavy bitumen blended with diluent (a dilbit) to meet pipeline specifications for density and viscosity. Peace Heavy is delivered to Edmonton on the Rainbow Pipeline system

Most Recent Sample Comments:
PH-617, Feb 8, 2013

Last 6 Samples

For the month of February, Peace River Heavy was consistent with historical values.

Monthly Reports

Basic Analysis

Property	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Density *(kg/m^3)*	923.8	931.1	930.5	928.4
Gravity *(°API)*	21.5	20.4	20.4	20.8
Sulphur *(wt%)*	4.94	4.96	5.00	5.08
MCR *(wt%)*	9.17	9.50	9.54	9.19
Sediment *(ppmw)*	128	99	97	168
TAN *(mgKOH/g)*	2.45	2.58	2.49	2.42
Salt *(ptb)*	16.6	14.2	15.0	21.5
Nickel *(mg/L)*	53.0	56.0	56.0	56.5
Vanadium *(mg/L)*	173.0	167.0	168.1	169.6
Olefins *(wt%)*	-	ND	ND	ND

*ND indicates a tested value below the instrument threshold.

Trend Charts

Open fullscreen charts

Choose a property: Density (kg/m^3)

Light Ends Summary

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
C3-	0.07	0.06	0.06	0.06
Butanes	0.84	0.88	0.84	0.83
Pentanes	7.17	6.77	6.84	7.05
Hexanes	5.79	5.29	5.36	5.41
Heptanes	3.91	3.63	3.76	3.58
Octanes	2.72	2.60	2.75	2.60
Nonanes	1.97	1.85	1.96	1.96
Decanes	0.92	0.93	0.94	0.90

BTEX

Property *(vol%)*	Most Recent Sample	6 Month Average	1 Year Average	5 Year Average
Benzene	0.25	0.21	0.22	0.22
Toluene	0.38	0.36	0.38	0.36
Ethyl Benzene	0.08	0.07	0.08	0.09
Xylenes	0.33	0.33	0.34	0.32

Distillation

TBP	ASTM D2892 & D5236	No assays available for this crude.
HTSD	ASTM D7169	Most Recent Sample Historical Average

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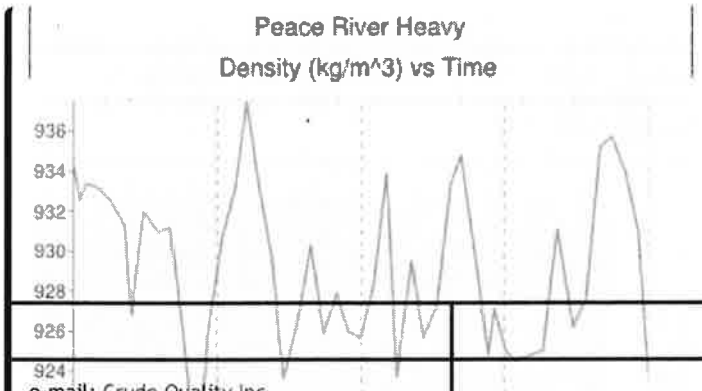

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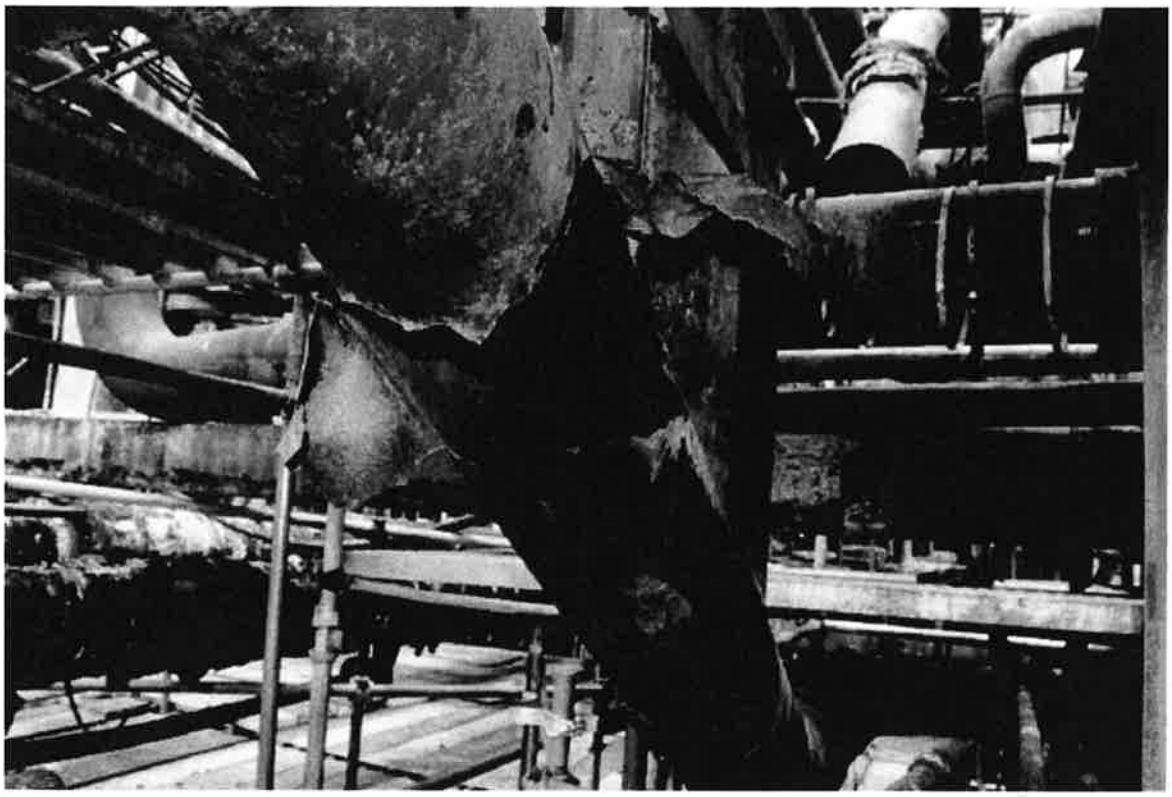
U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INTERIM INVESTIGATION REPORT

CHEVRON RICHMOND REFINERY FIRE



CHEVRON RICHMOND REFINERY

RICHMOND, CALIFORNIA

AUGUST 6, 2012

KEY ISSUES

- INHERENTLY SAFER DESIGN
- DAMAGE MECHANISM HAZARD REVIEW
- EFFECTIVE ANALYSIS OF PROCESS SAFEGUARDS IN PROCESS HAZARD ANALYSIS

Summary

On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California, experienced a catastrophic pipe failure in the #4 Crude Unit. The pipe ruptured, releasing flammable, hydrocarbon process fluid which partially vaporized into a large vapor cloud that engulfed nineteen Chevron employees. All of the employees escaped, narrowly avoiding serious injury. The flammable portion of the vapor cloud ignited just over two minutes after the pipe ruptured. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area. In the weeks following the incident, approximately 15,000 people from the surrounding area sought medical treatment due to the release. Testing commissioned by the U.S. Chemical Safety and Hazard Investigation Board (CSB) and the California Division of Occupational Safety and Health (Cal/OSHA) determined that the pipe failed due to thinning caused by sulfidation corrosion, a common damage mechanism in refineries. As a result of the incident, the Chevron Richmond Refinery crude unit remains out of commission over eight months later. In addition, Cal/OSHA issued the refinery 17 citations related to the incident and eight additional citations, with a total proposed fine of nearly one million dollars. In this interim report, the CSB is issuing recommendations to Chevron, the City of Richmond, Contra Costa County, Cal/OSHA, the State of California, and the U.S. Environmental Protection Agency, addressing the need for inherently safer design, rigorous and documented damage mechanism hazard reviews, and thorough analyses of process safeguards.

This interim investigation report contains detailed analyses of and makes recommendations to Chevron and regulatory bodies at the local, state, and federal level. The CSB believes the findings and recommendations presented in this report can be applied to refineries, chemical plants, and other industries nationwide to improve process safety.

The CSB plans to release a comprehensive Final Investigation Report later in 2013 that will include analyses and recommendations relating to technical and regulatory investigation findings which are not included in this interim report. The Final Investigation Report will cover topics including: the importance of having a competent, well-funded regulator and an adaptable regulatory regime; Chevron safety culture; process safety indicator data collection and reporting; emergency planning and response; stop work authority; and recommendations for improvement of petroleum industry standards and recommended practices. Some of these issues are previewed at the end of this interim report under *Additional Issues Currently Under Investigation.*

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Acronyms and Abbreviations

ALARP	As Low As Reasonably Practicable
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BIN	Business Improvement Network
bpd	Barrels Per Day
BPTC	BP Texas City
CAA	Clean Air Act
Cal/OSHA	California Division of Occupational Safety and Health
CCPS	Center for Chemical Process Safety
CCR	California Code of Regulations
Chevron ETC	Chevron Energy Technology Company
CML	Condition Monitoring Locations
CSB	U.S. Chemical Safety and Hazard Investigation Board
CSHO	Compliance Safety and Health Officer
CWS	Community Warning System
EPA	Environmental Protection Agency
°F	degree Fahrenheit
HSE	Health and Safety Executive
ISO	Industrial Safety Ordinance
ISS	Inherently Safer Systems
IST	Inherently Safer Technology
KPI	Key Process Indicator

LEPC	Local Emergency Planning Committee
LOPA	Layers of Protection Analysis
MOC	Management of Change
NEP	National Emphasis Program
OEM	U.S. EPA Office of Emergency Management
OSHA	Occupational Safety and Health Administration
P&P	Policy and Procedures
PHA	Process Hazard Analysis
PMI	Positive Materials Identification
psig	Pounds Per Square Inch Gauge
PSM	Process Safety Management
RISO	City of Richmond Industrial Safety Ordinance
RLOP	Richmond Lube Oil Project
RMP	Risk Management Plan
SIP	Shelter-In-Place
TML	Thickness Monitoring Location
UK	United Kingdom
USW	United Steelworker International Union
wt. %	Weight Percent

Background and Findings

1. On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California (Chevron Richmond Refinery), experienced a catastrophic pipe rupture in the #4 Crude Unit (crude unit). The ruptured pipe released a flammable hydrocarbon process fluid which then partially vaporized into a large vapor cloud that engulfed nineteen Chevron U.S.A. Inc. (Chevron) employees. At 6:33 pm, approximately two minutes after the release, the flammable portion of the vapor cloud ignited.[i] Eighteen of the employees safely escaped from the cloud just before ignition; one employee, a firefighter, was inside a fire engine that caught fire when the vapor cloud ignited (Figure 1). Because he was wearing full body fire-fighting protective equipment, he was able to make his way to safety. Six Chevron employees suffered minor injuries during the incident and subsequent emergency response efforts.

[i] Surveillance footage provided by Chevron. Chevron clarified to CSB that video time is approximately 5 minutes out of sync. The video can be found at http://www.csb.gov/videoroom/detail.aspx?VID=69 (accessed February 8, 2013).

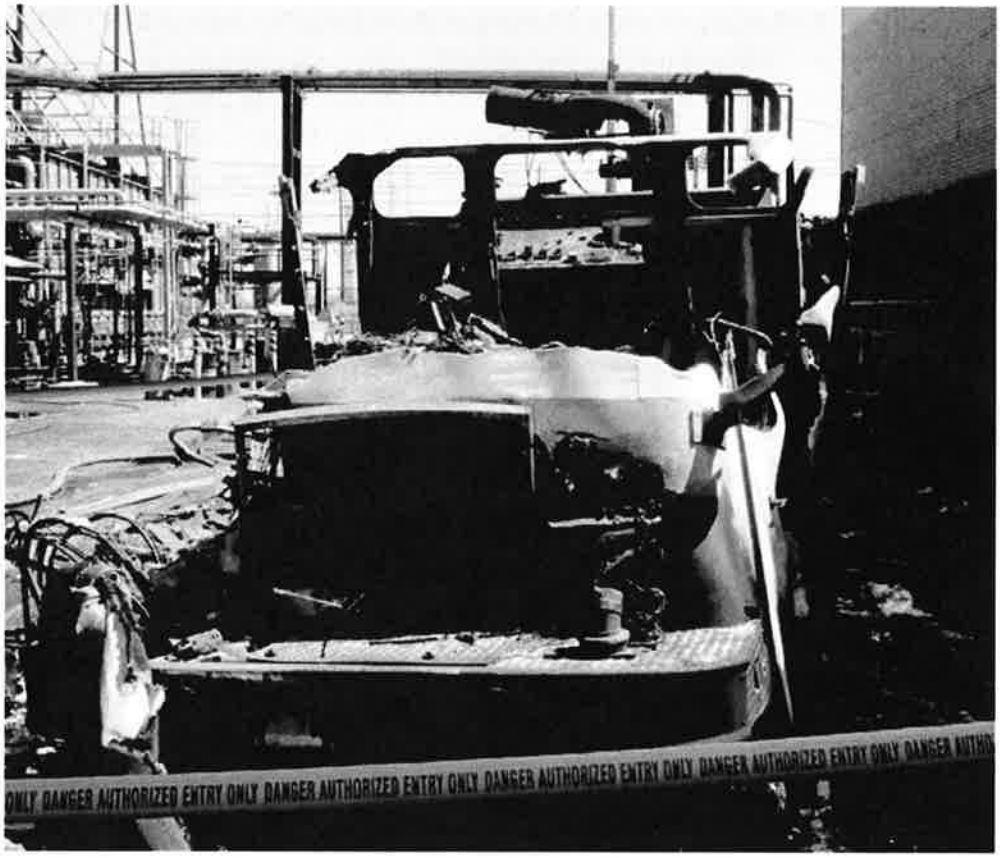

Figure 1. The burned remains of the fire truck that was consumed by the fire. A firefighter was in the cab when the vapor cloud ignited. The fire truck was positioned approximately 65 feet from the leak location.

2. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area (Figures 2 and 3). This resulted in a Community Warning System (CWS) Level 3 alert,[i] and a shelter-in-place[ii] (SIP) was issued at 6:38 pm[1] for the cities of Richmond, San Pablo, and North Richmond. It was lifted later that night at 11:12 pm after the fire was fully under control. In the weeks following the incident, nearby medical facilities received over 15,000 members of the public seeking treatment for ailments including breathing problems, chest pain, shortness of breath, sore throat, and headaches. Approximately 20 people were admitted to local hospitals as inpatients for treatment.

Figure 2. Vapor cloud (white) over Richmond area and smoke (black) from Chevron Richmond Refinery fire as seen from San Rafael in Marin County.[2]

[i] A Community Warning System Level 3 alert indicates that a facility within Contra Costa County has had a release that has offsite impact and is categorized by any of the following:

1. Off-site impact that may cause eye, skin, nose and/or respiratory irritation to the general population.
2. Fire, explosion, heat, or smoke with an off-site impact. Example: On a process unit/storage tank where mutual aid is requested to mitigate the event and the fire will last longer than 15 minutes.
3. Hazardous material or fire incident where the incident commander or unified command, through consultation with the Contra Costa Health Services Hazardous Material Incident Response Team, requests that sirens should be sounded.

See http://cchealth.org/hazmat/pdf/incident_notification_policy.pdf (accessed April 9, 2013).

[ii] Contra Costa County considers a shelter-in-place to include going inside a home or nearest building, closing doors and windows, and turning off heating, ventilation, and air conditioning. *See* http://cchealth.org/emergencies/shelter-in-place.php (accessed February 6, 2013).

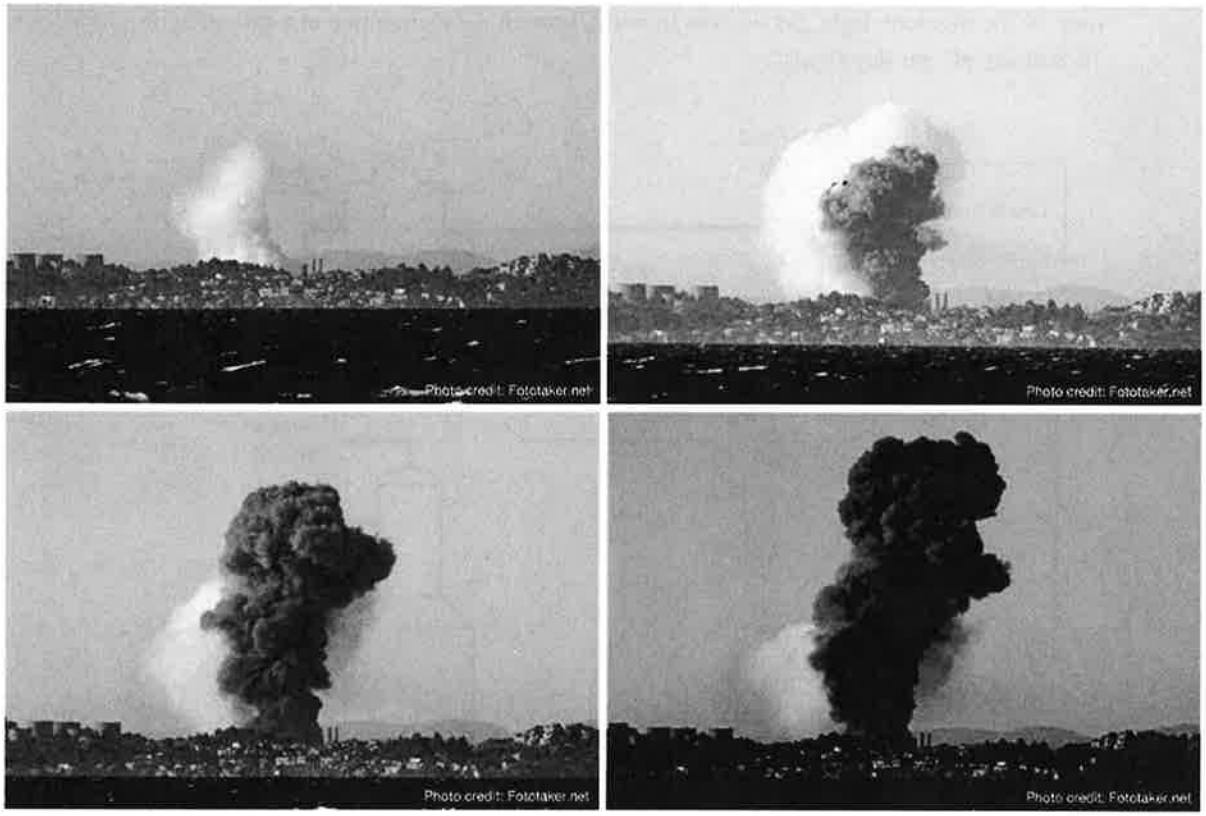

Figure 3. Initial vapor cloud formation (white cloud) and subsequent ignition (black smoke) as seen from a pier in San Francisco, California.

3. The incident occurred from the piping referred to as the "4-sidecut" stream, one of several process streams exiting the C-1100 Crude Unit Atmospheric Column (Figure 4).[i] A plot plan of the crude unit shows the leak location relative to C-1100 (Figure 5). As shown in Figure 6, light gas oil (the crude unit 4-sidecut process fluid) exits the atmospheric column via a 20-inch nozzle and is split into a 12-inch line and an 8-inch line. The August 6, 2012, pipe rupture (Figure 7) occurred on a 52-inch long component[ii] of the 4-sidecut 8-inch line (the 52-inch component). The line operated at a temperature of 640 degrees Fahrenheit (°F)[iii] and had an operating pressure of approximately 55 pounds per square inch gauge (psig) at the rupture location. At the

[i] The atmospheric column separates crude oil feed into different streams through distillation. These streams are further processed in other units in the refinery.

[ii] The term "component" refers to a portion of piping between welds or flanges. It includes straight run piping and pipe fittings.

[iii] The auto-ignition temperature for this process, the temperature at which a material will combust in the presence of sufficient oxygen without an ignition source, was also 640 °F. This number is based on the Chevron Light Gas Oil Material Safety Data Sheet. Chemical testing of 4-sidecut samples following the incident indicated lower auto-ignition temperatures; however, these samples may not have been representative of typical 4-sidecut process fluid.

time of the incident, light gas oil was flowing through the 8-inch line at a rate of approximately 10,800 barrels per day (bpd).[i]

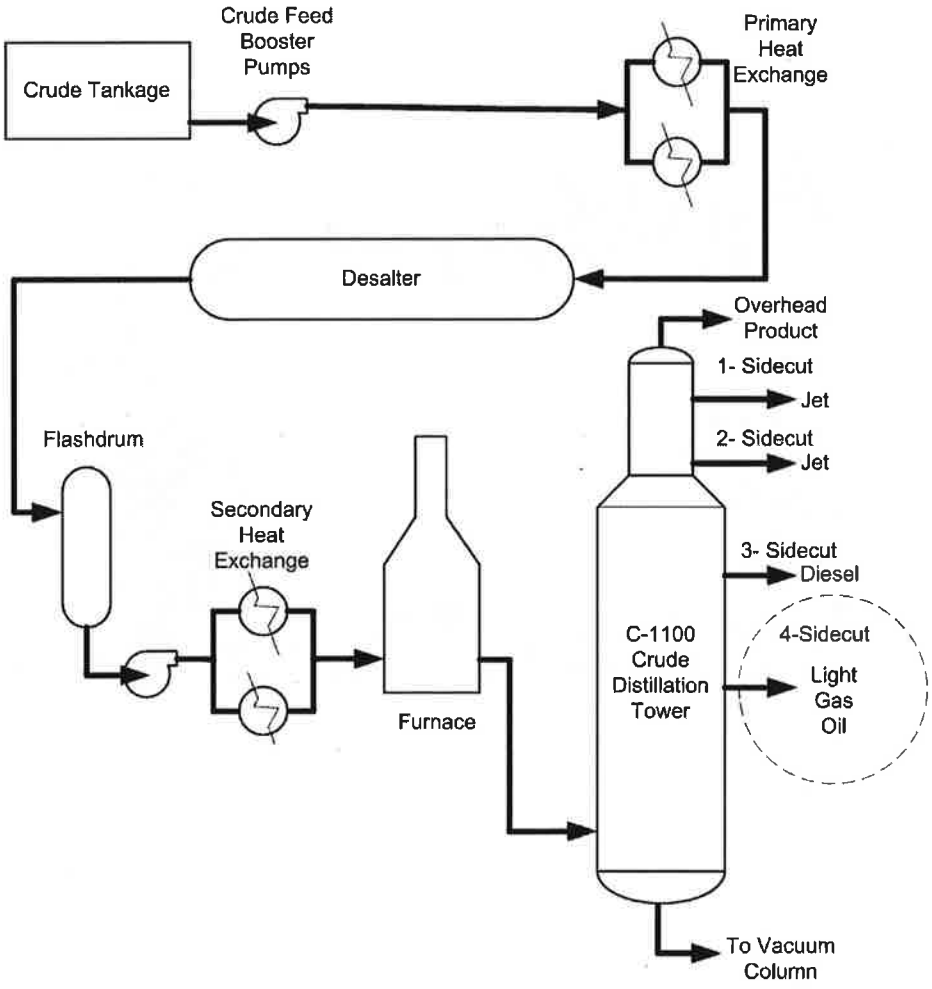

Figure 4. C-1100 Crude Unit Atmospheric Column and Upstream Process Equipment.

[i] This is the equivalent of 315 gallons per minute (gpm). A barrel equals 42 gallons.

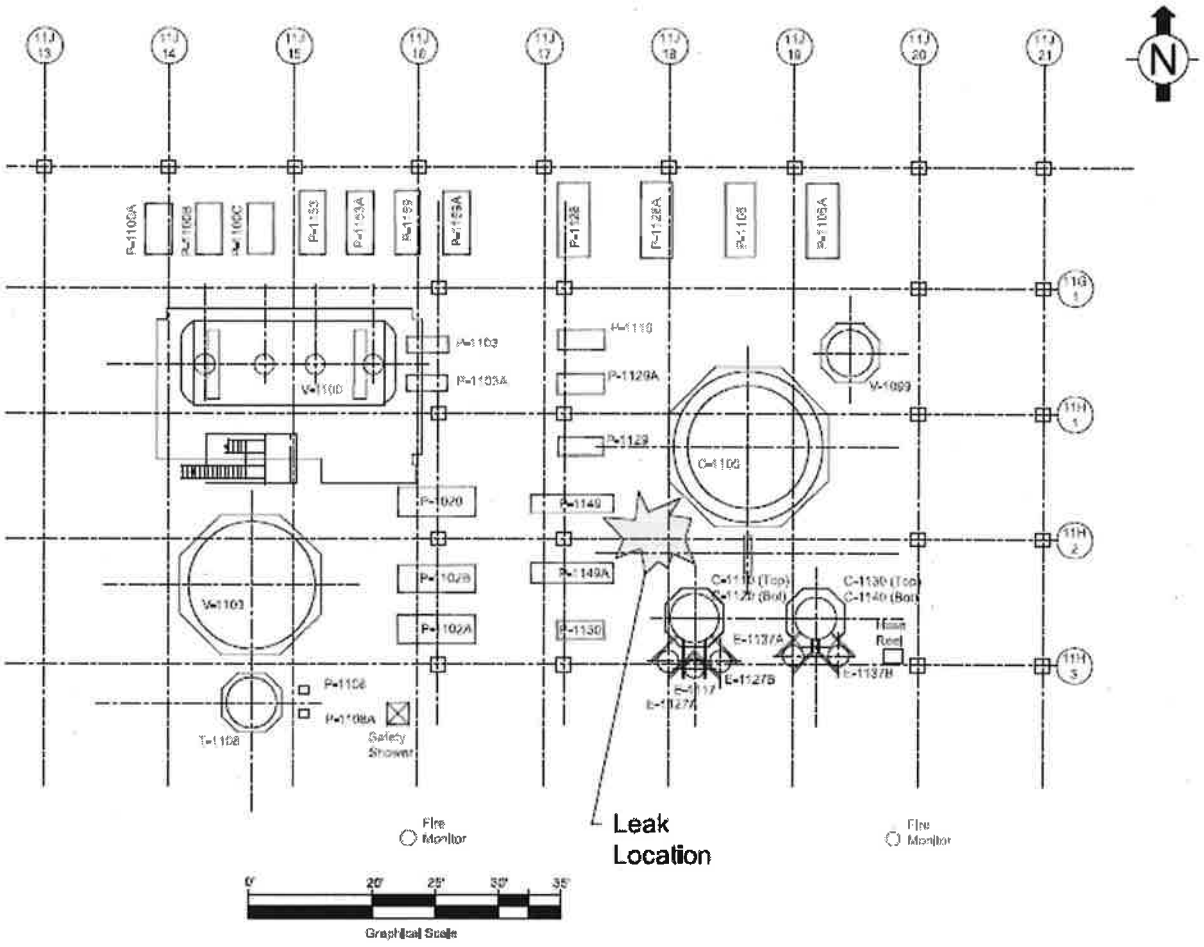

Figure 5. Overhead view of the equipment in the #4 Crude Unit showing the leak location, commonly referred to as a plot plan.

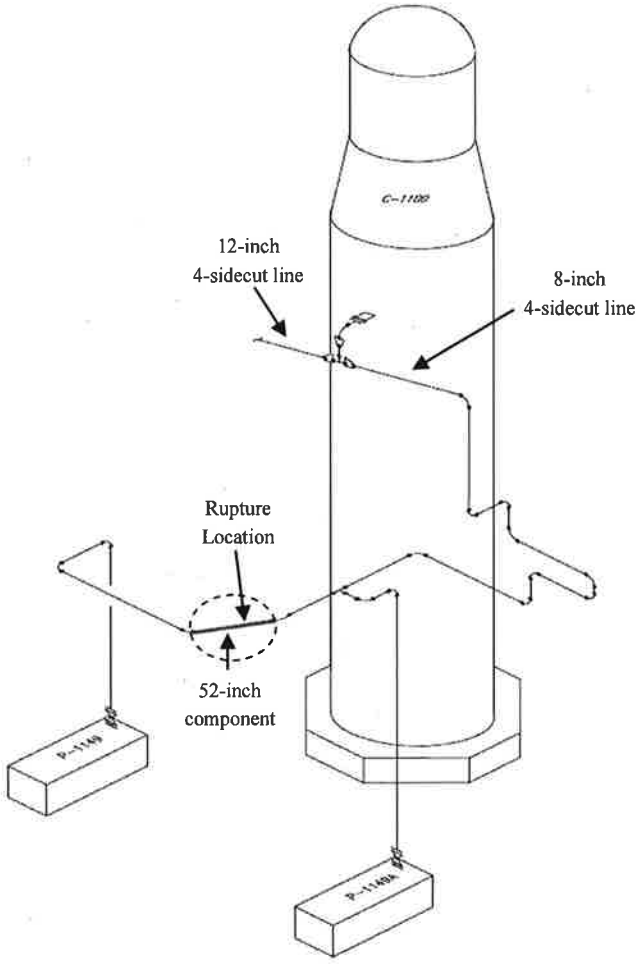

Figure 6. 4-sidecut line configuration and rupture location.

4. The CSB commissioned Anamet, Inc., a materials engineering and laboratory testing company, to conduct testing of the 4-sidecut pipe, including the failed 52-inch component. The testing concluded that the rupture was due to pipe wall thinning caused by sulfidation corrosion,[3] which is discussed below.

5. Anamet's metallurgical analysis found that the 52-inch component where the rupture occurred had experienced extreme thinning; the average wall thickness near the rupture location was approximately 40 percent thinner than a dime[i] (the thinnest American coin). Between 1976 and 2012, the 52-inch piping component had lost, on average, 90 percent of its original wall thickness in the area near the rupture. The piping had an initial nominal wall thickness of 0.322-inch[ii] when it was installed in 1976.

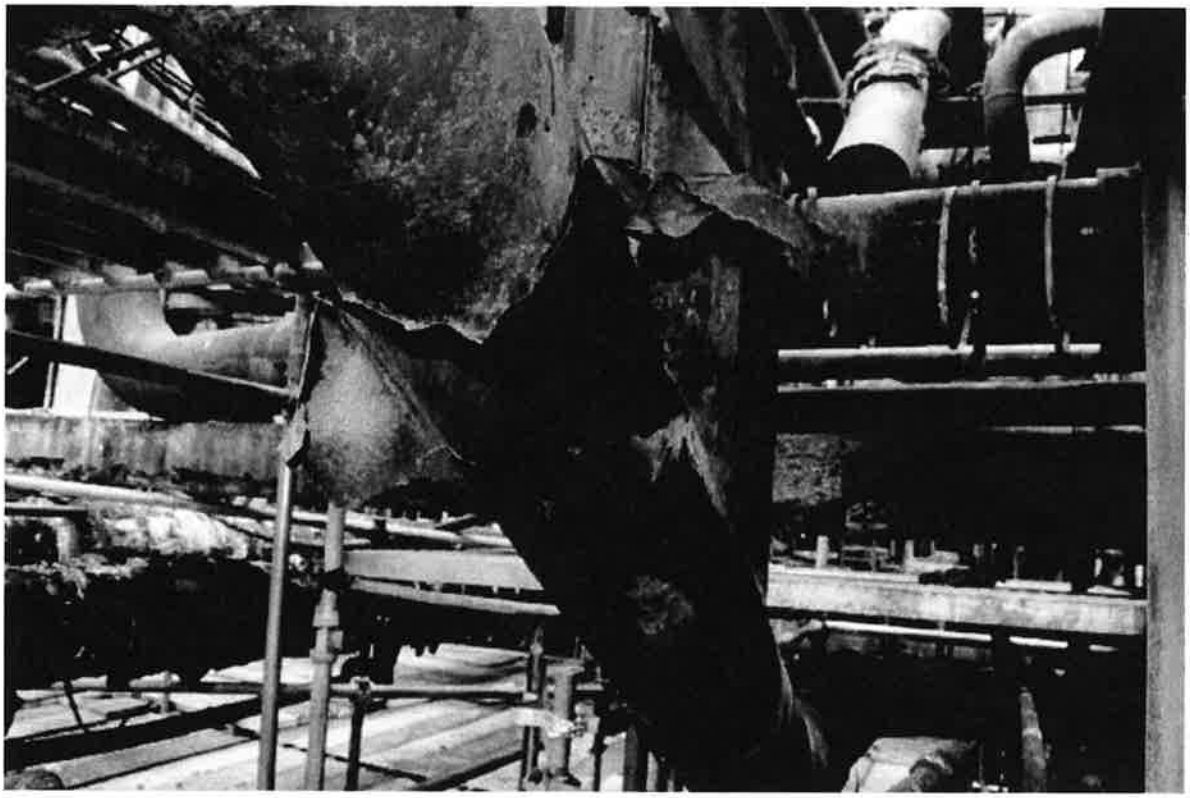

Figure 7. Photo of rupture on 4-sidecut 52-inch component.

[i] The U.S. Mint reports that a dime has a thickness of 1.35 mm, or 0.053 inches. Information can be found at http://www.usmint.gov/about_the_mint/?action=coin_specifications (accessed February 14, 2013).

[ii] This portion of the 4-sidecut line was constructed of 8-inch Schedule 40 carbon steel piping.

Sulfidation Corrosion

6. Sulfidation corrosion is a damage mechanism[i] that is well understood in the refining industry. The sulfidation corrosion industry guidance document, American Petroleum Institute (API) Recommended Practice (RP) 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*[ii] notes:

> [Sulfidation] …is not a new phenomenon, but was first observed in the late 1800s in a pipe still (crude separation) unit, due to the naturally occurring sulfur compounds found in crude oil. When heated for separation, the various fractions in the crude were found to contain sulfur compounds that corroded the steel equipment.[4]

7. Sulfidation corrosion, also known as sulfidic corrosion,[5] is a damage mechanism that causes thinning in iron-containing materials, such as steel, due to the reaction between sulfur compounds and iron at temperatures ranging from 450 °F to 800 °F.[6] This damage mechanism causes pipe walls to gradually thin over time. Sulfidation corrosion is common in crude oil distillation[iii] where naturally occurring sulfur and sulfur compounds found in crude oil feed, such as hydrogen sulfide,[iv] are available to react with steel piping and equipment. Process variables that affect corrosion rates include the total sulfur content of the oil, the sulfur species present, flow conditions, and the temperature of the system. Virtually all crude oil feeds contain sulfur compounds and, as a result, sulfidation corrosion is a damage mechanism present at every refinery that processes crude oil. Sulfidation corrosion can cause thinning to the point of pipe failure when not properly monitored and controlled.

8. The reaction between sulfur and iron produces a layer of iron sulfide scale[v] on the inside surface of piping.[7] This reaction can be compared to that of oxygen and iron which also produces a scale, commonly known as rust. The type of scale formed by sulfidation corrosion is dependent upon the components contained in the steel. Certain scales formed are protective and actually reduce the reaction rate between sulfur compounds and iron, minimizing sulfidation corrosion

---

[i] Piping damage mechanisms are any type of deterioration encountered in the refining and chemical process industry that can result in flaws/defects that can affect the integrity of piping (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical or chemical impacts). *See* API 570. "Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems." 3rd ed., Section 3.1.1.5, November 2009.

[ii] API RP 939-C is one of several relevant American Petroleum Institute recommended practices and standards under evaluation by the CSB as part of this investigation. To the casual observer API RP 939-C appears to obligate the industry to take significant actions. However, the CSB concluded it was written to be permissive so that industry compliance with specific provisions would not be required. The complete findings from this evaluation will be included in the CSB's Final Report.

[iii] Distillation separates mixtures into broad categories of its components by heating the mixture in a distillation column where different products boil off and are recovered at different temperatures. *See* http://www.eia.gov/todayinenergy/detail.cfm?id=6970 (accessed April 4, 2013).

[iv] Hydrogen sulfide is the most aggressive sulfur compound that causes sulfidation corrosion.

[v] Scale is a nonmetallic layer on the surface of metals and is often a result of corrosion.

rates. For instance, sulfidation corrosion affecting steel alloys containing greater than two weight percent (wt. %) chromium produces a protective scale that inhibits the reaction between the iron and sulfur compounds, thereby reducing corrosion rates.[i] With increasing percentages of chromium, the reaction is further slowed, greatly diminishing corrosion rates.[8,ii] For example, stainless steel (an 18 wt. % chromium alloy) is nearly 15 times more resistant to sulfidation corrosion than 9-Chrome (a 9 wt. % chromium alloy).[9] Conversely, sulfidation corrosion rates are significantly higher in steels containing very little chromium. Carbon steel, the Chevron 4-sidecut line material of construction, was manufactured with a maximum concentration of 0.40 % chromium.[10] The scale formed on carbon steel is less protective and allows continued reaction between the sulfur compounds and iron.[11] Thus, carbon steel corrodes at a rate that is significantly faster than other materials of construction, such as high chromium steels.

9. In addition to its inherently faster rate of sulfidation corrosion when compared with higher chromium steels, carbon steel also experiences significant variation in corrosion rates due to variances in silicon content, a component used in the steel manufacturing process. Carbon steel piping containing silicon content less than 0.10 wt. % can corrode at accelerated rates,[12] up to sixteen times faster than carbon steel piping containing higher percentages of silicon as shown in Figure 8. This figure shows how carbon steel corrosion rates can greatly vary depending on silicon content.

[i] At greater than two wt. % chromium, sulfur compounds react with the steel to form $FeCr_2S_4$ scale. This scale provides more protection than the FeS scale that forms on carbon steel piping. *See* Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." *17th International Corrosion Congress.* Las Vegas: NACE International, 2008.

[ii] It has also been found that chromium "poisons" the decomposition of sulfur compounds to hydrogen sulfide which also slows down the sulfidation corrosion rate. *See* Couper, A.S. "High Temperature Mercaptan Corrosion of Steels." *19th Annual Conference of the National Association of Corrosion Engineers.* Pages 396t-401t, New York: March 1963.

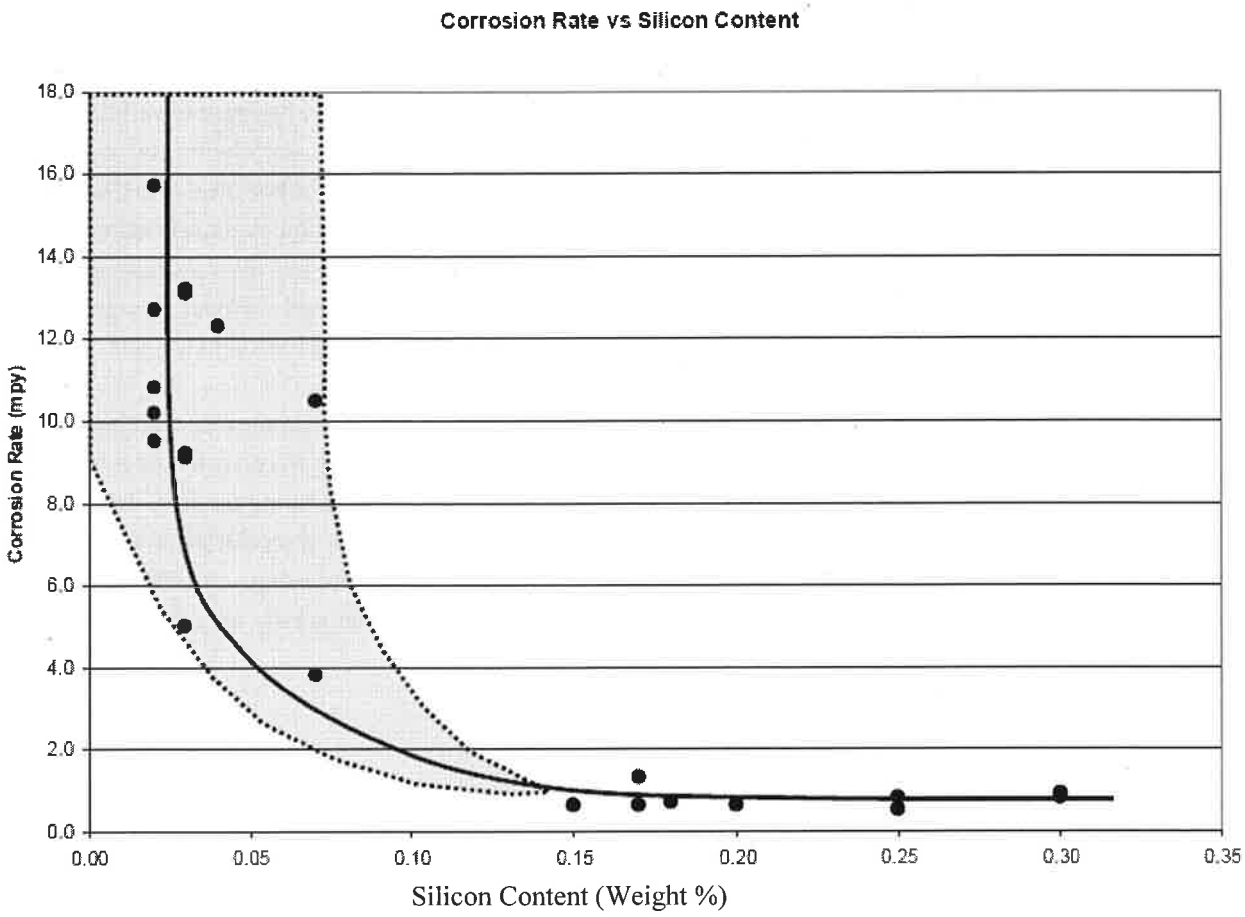

Figure 8. This graph shows how corrosion rates increase in carbon steel containing decreasing percentages of silicon. This information can be found in Annex C of API RP 939-C.[i]

10. The refining industry has been aware of increased rates of sulfidation corrosion in low-silicon carbon steel piping since as early as 1974,[13] nearly 40 years before the August 6, 2012, incident and two years before the Chevron crude unit was constructed. Prior to the incident, Chevron documented its understanding of the significant consequences of sulfidation corrosion. This is reflected in Chevron's *Corrosion Prevention and Metallurgy Manual*, which states:

> Sulfidation corrosion has caused severe fires and fatalities in the refining industry, primarily because it causes corrosion over a relatively large area, so failures tend to involve ruptures or large leaks rather than pinhole leaks. It can be insidious in that moderately high corrosion rates can go undetected for years before failure. Finally, process changes that increase the temperature or sulfur content can creep up over time and

[i] The y-axis of this figure is in units of mils per year (mpy). A "mil" is 1/1000 inch.

multiply corrosion rates so that what was thought to be a low corrosion rate system becomes corrosive enough to fail before the increased corrosion rate is recognized.

11. Carbon steel piping is manufactured to meet certain specifications, including American Society for Testing and Materials (ASTM) A53B,[14] ASTM A106,[15] and API 5L.[16] ASTM A53B and API 5L do not contain minimum silicon content requirements for carbon steel piping,[17] while ASTM A106 requires the piping to be manufactured with a minimum silicon content of 0.10 wt. %. As a result, manufacturers have used different levels of silicon in the carbon steel pipe manufacturing process. Thus, depending on the manufacturing specification for carbon steel susceptible to sulfidation corrosion, corrosion rates could vary depending on the silicon content within the steel.

12. In the mid 1980s, pipe manufacturers began to simultaneously comply with all three manufacturing specifications (ASTM A53B, ASTM A106, and API 5L) when manufacturing carbon steel piping. The majority of carbon steel piping purchased following this time period likely has a minimum of 0.10 wt. % silicon content. However, piping purchased and installed prior to the mid-1980s could still contain low silicon components that are susceptible to high, variable sulfidation corrosion rates.

13. Over 95 percent of the 144 refineries in operation in the U.S., including the Chevron Richmond Refinery,[i] were built before 1985,[18] and thus before piping manufacturers began producing carbon steel in compliance with all three manufacturing specifications. Therefore, the original carbon steel piping in these refineries is likely to contain varying percentages of silicon content and may experience highly variable sulfidation corrosion rates.

14. The Chevron Richmond Refinery 4-sidecut piping circuit containing the 52-inch component that failed was constructed of ASTM A53B carbon steel, which had no minimum specification for silicon content. Post-incident testing of samples of the 4-sidecut piping from the Chevron Richmond Refinery identified silicon content ranging from 0.01 wt. % to 0.2 wt. %. Of twelve samples taken from the 8-inch and 12-inch 4-sidecut line, six had a silicon concentration of less than 0.10 wt. %. The 52-inch pipe component that ruptured on the day of the incident had a silicon content of only 0.01 wt. %. The elbow component directly upstream of the 52-inch component that failed had a silicon concentration of 0.16 wt. % and showed considerably less thinning (Figure 9).

[i] The Chevron Richmond Refinery was constructed in 1902.

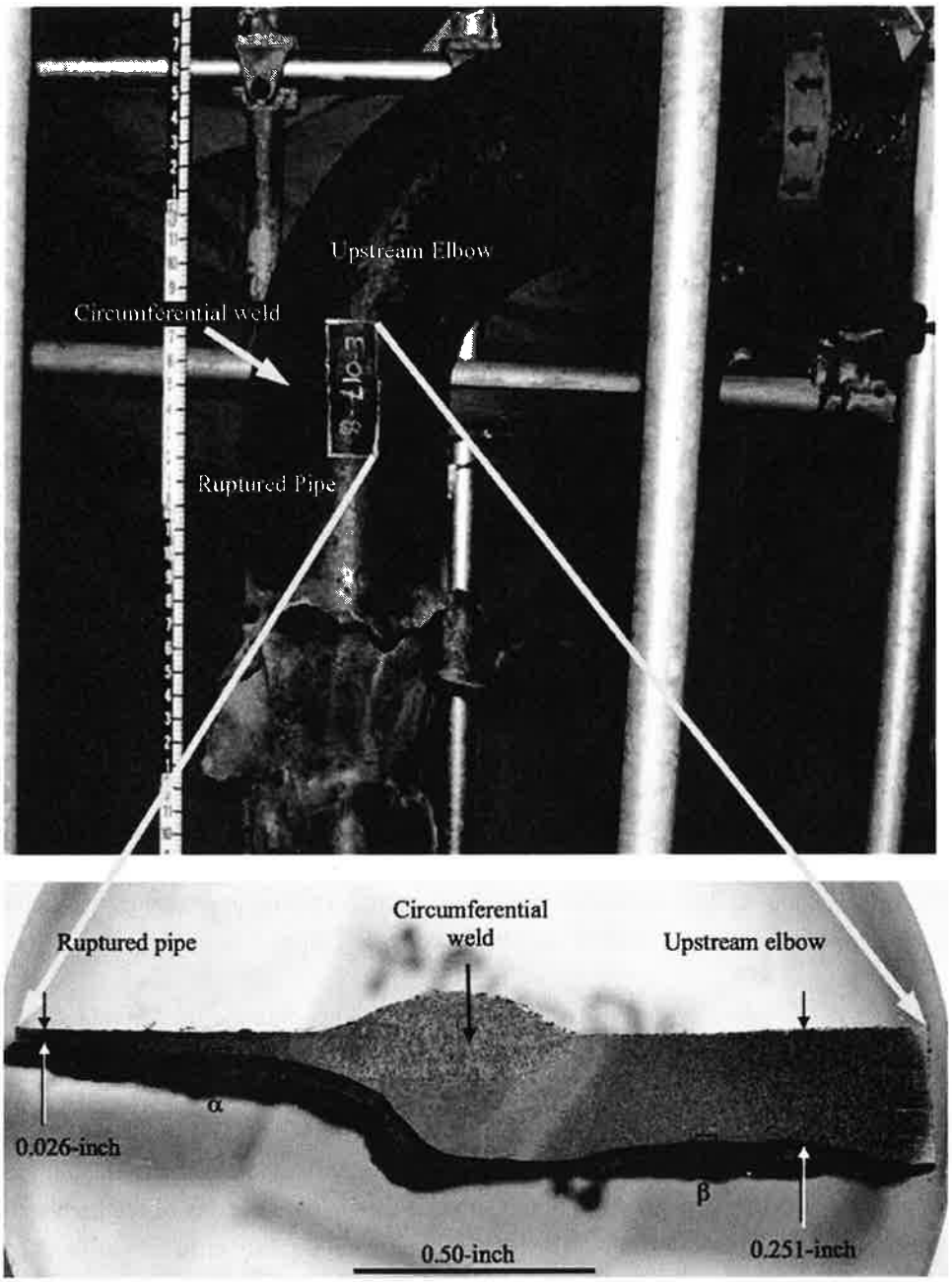

Figure 9. 4-sidecut piping sample (E-017-8) analyzed by Anamet Labs showing the relative thickness of low silicon piping on the left and the high silicon piping on the right. The ruptured pipe component (left) contained 0.01 % silicon and the upstream elbow component (right) contained 0.16 % silicon.[19] The initial nominal thickness of this piping was 0.322-inch.

Sulfidation Corrosion Inspection Techniques

15. As evidenced by the chemical analysis performed on the Chevron 4-sidecut piping post-incident, carbon steel piping components within a single circuit[i] can contain varying percentages of silicon, resulting in a large variation in sulfidation corrosion rates by component. Historically, sulfidation corrosion monitoring techniques required the measurement of pipe thickness at only a minimal number of permanent Condition Monitoring Locations (CMLs)[ii] along the piping. These CMLs are most frequently placed on elbows and fittings.[iii] However, due to details of the manufacturing process, carbon steel pipe fittings generally contain high percentages of silicon.[20] When measurements are only taken at high-silicon containing fittings, the measurements can fail to identify high corrosion rates within a pipe circuit caused by low-silicon components. At the Chevron Richmond Refinery, the 4-sidecut piping had a total of 24 CMLs[iv] on piping and fittings. The CSB found that there were no CMLs placed on the low silicon piping component that failed. Chevron identified accelerated corrosion in the 52-inch component in a 2002 inspection. However, no CML was added to ensure future monitoring, and the 52-inch component was not inspected again. Instead, the CSB found that Chevron relied on inspection data gained primarily from high silicon pipe-fitting components, such as elbow components. This inspection data did not reflect the corrosion rates of the lower-silicon components of the 4-sidecut piping. Relying on the limited inspection data from the CMLs on the high silicon components, Chevron management denied multiple recommendations to replace the 4-sidecut line. As illustrated by the Chevron incident, inspection techniques alone may not accurately identify the most aggressive corrosion rates throughout an entire circuit of carbon steel piping. Low-silicon components can remain uninspected and unidentified until failures such as the August 6, 2012, Chevron incident occur. As will be discussed below, upgrading metallurgy is a more effective means of managing sulfidation corrosion.

16. Determining silicon content in existing carbon steel piping and equipment in the field is a difficult undertaking. To properly characterize the silicon content in each component in a piping circuit, every component must be inspected. This is known as 100 percent component inspection. Two techniques are currently used to determine silicon content in existing carbon steel piping circuits with unknown chemical composition: performing chemical analysis and pipe wall thickness measurements of every component.

---

[i] A piping circuit is a length of pipe and the fittings associated with a particular process service that operate at similar conditions. A circuit usually begins and ends at either a branch or a piece of process equipment such as a vessel or a pump. Reference to piping by circuits allows piping to be grouped conveniently by proximity and operating service. Piping circuits may also be referred to as piping runs.

[ii] A condition monitoring location (CML) is a designated area where periodic thickness examinations are conducted. Each CML represents as many as four inspection locations located circumferentially around the pipe. CMLs are also referred to as thickness monitoring locations (TMLs). CML was historically referred to as corrosion monitoring locations (CMLs) and that terminology is sometimes still used within the industry.

[iii] A fitting is a piping component usually associated with a change in direction or diameter.

[iv] Many of these CMLs were added during the 2011 turnaround.

17. Many field-portable instruments used for positive material identification cannot adequately identify silicon content.[21] If original manufacturing quality assurance data[i] are not available, as is generally the case with older plants, then chemical verification requires destructive testing. Metal shavings must be taken from each carbon steel piping component for chemical analysis in a laboratory.[22] This method requires that the insulation be removed for access to the piping so that each individual piping component can be sampled and verified.

18. Carbon steel components containing low concentrations of silicon can also potentially be identified by performing thickness measurements of every component within a carbon steel circuit.[23] This practice is only useful if the piping circuit has been exposed to sulfidation corrosion for a long enough time period so that variances in corrosion rate caused by differences in silicon content may be detected. Chemical analysis is therefore the most accurate technique to identify low-silicon carbon steel components. As with chemical analysis, the thickness measurement method requires that each individual piping component be identified by removing insulation (so every weld seam can be located), a time consuming and costly undertaking, or by using non-destructive examination techniques. Thickness measurements on high temperature piping typically can only be done accurately and safely during unit turnarounds.[ii] Although these various methods were available to detect the location of the field welds, Chevron had not used them to identify the 4-sidecut pipe segment locations.

19. API Recommended Practice 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries* describes the challenges faced when attempting to thoroughly inspect carbon steel lines susceptible to sulfidation corrosion. The recommended practice states that older ASTM A53 piping, such as the Chevron piping that failed on August 6th, creates a "major inspection challenge"[24] and that "unless the refinery is fortunate enough to have located an inspection point on that particular [low silicon] section of pipe or fitting, it is very difficult to detect the thinning component."[25] It states that in some applications, carbon steel will appear to be adequate based on measured corrosion rates until failure occurs at some undocumented or unidentified low-silicon component.[26]

20. Unlike silicon concentration, the chromium concentration of steel can easily be verified in the field using portable positive material identification instruments. In addition, steel alloys containing at least 9 wt. % chromium are more resistant to sulfidation corrosion and do not run the risk of extreme variations in corrosion rates within components in the same piping circuit.[iii] This makes alloys with higher chromium content an inherently safer choice in high temperature

[i] Manufacturing quality assurance data, also known as mill data, provides the chemical composition of the steel.
[ii] A "turnaround" is a scheduled shutdown of a process unit to perform maintenance, repairs, upgrades, and inspection of process equipment.
[iii] The protective scale, $FeCr_2S_4$, begins to be the dominant scale formed in steels containing a chromium content of five wt. %. The 5Cr steel alloy can be manufactured to contain anywhere from 4% to 6% chromium. Thus, "the sulfidation corrosion rate can vary dramatically in 5Cr steels even in the same operating environment." *See* Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." *17th International Corrosion Congress.* Las Vegas: NACE International, 2008.

sulfidation corrosion environments.[i] As shown in the Modified McConomy Curves[ii] from API RP 939-C (Figure 10), 9-Chrome[iii] corrodes 15 times faster than stainless steel,[iv] and carbon steel[v] corrodes 125 times faster than stainless steel.[27]

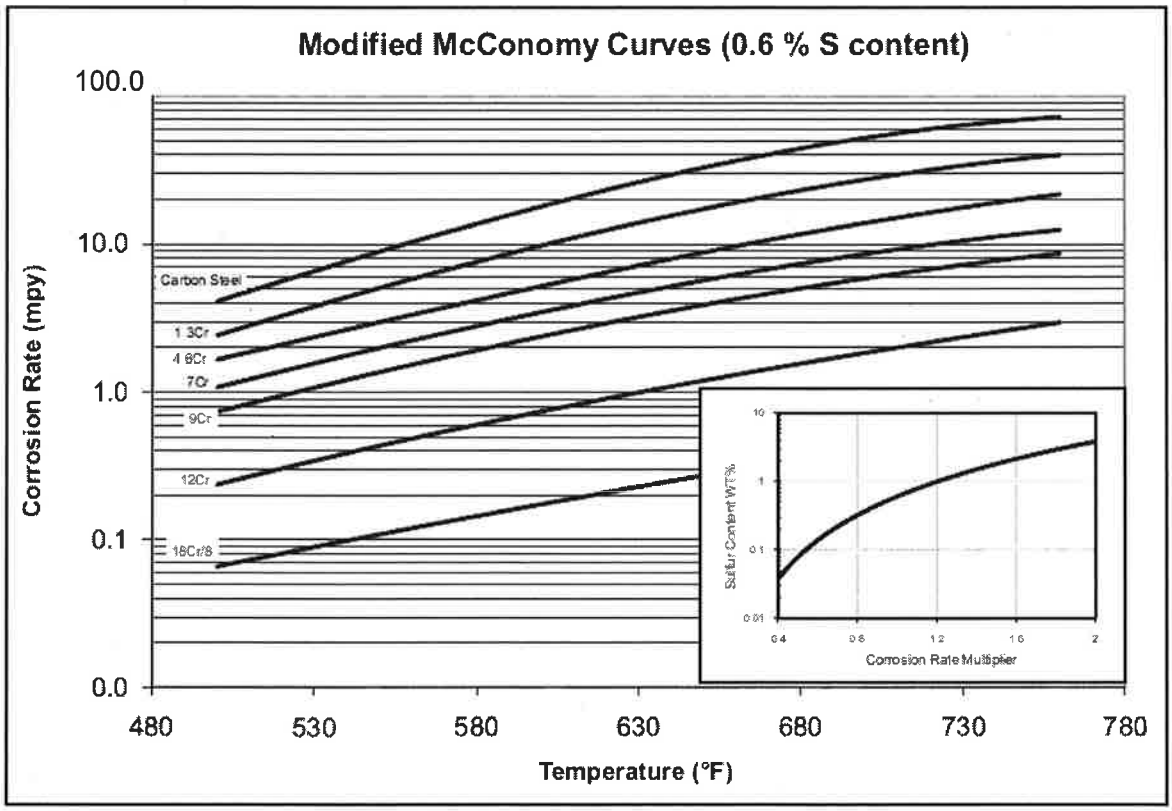

Figure 10. Modified McConomy Curves from API RP 939-C.

[i] Steels with higher chromium content are inherently safer than carbon steel with respect to sulfidation corrosion. However, analysis is still required to ensure that the best material of construction is selected.

[ii] Modified McConomy Curves are the set of curves API RP 939-C uses to predict sulfidation corrosion rates versus temperature for several steel alloys.

[iii] 9-Chrome contains 9 wt. % chromium.

[iv] Stainless steel contains 18 wt. % chromium.

[v] ASTM A53B carbon steel contains a maximum of 0.40 wt. % chromium.

Chevron Sulfidation Corrosion Knowledge and Expertise

21. Figure 11 shows a timeline of Chevron's key sulfidation events. Chevron technical staff has considerable knowledge and expertise regarding sulfidation corrosion, specifically with respect to corrosion rate variations caused by differing silicon concentration in carbon steel piping. Chevron employees have authored industry papers on sulfidation corrosion and had significant influence in the development of the industry sulfidation corrosion recommended practice, API RP 939-C. This recommended practice, first published in 2009, was developed under Chevron leadership. At the approximate time of publication of API RP 939-C, Chevron Energy Technology Company (Chevron ETC)[i] created an internal document on the subject of sulfidation corrosion. Chevron ETC metallurgists released a formal report dated September 30, 2009 (nearly 3 years prior to the incident) to Chevron refinery-based reliability managers and chief inspectors entitled *Updated Inspection Strategies for Preventing Sulfidation Corrosion Failures in Chevron Refineries*.

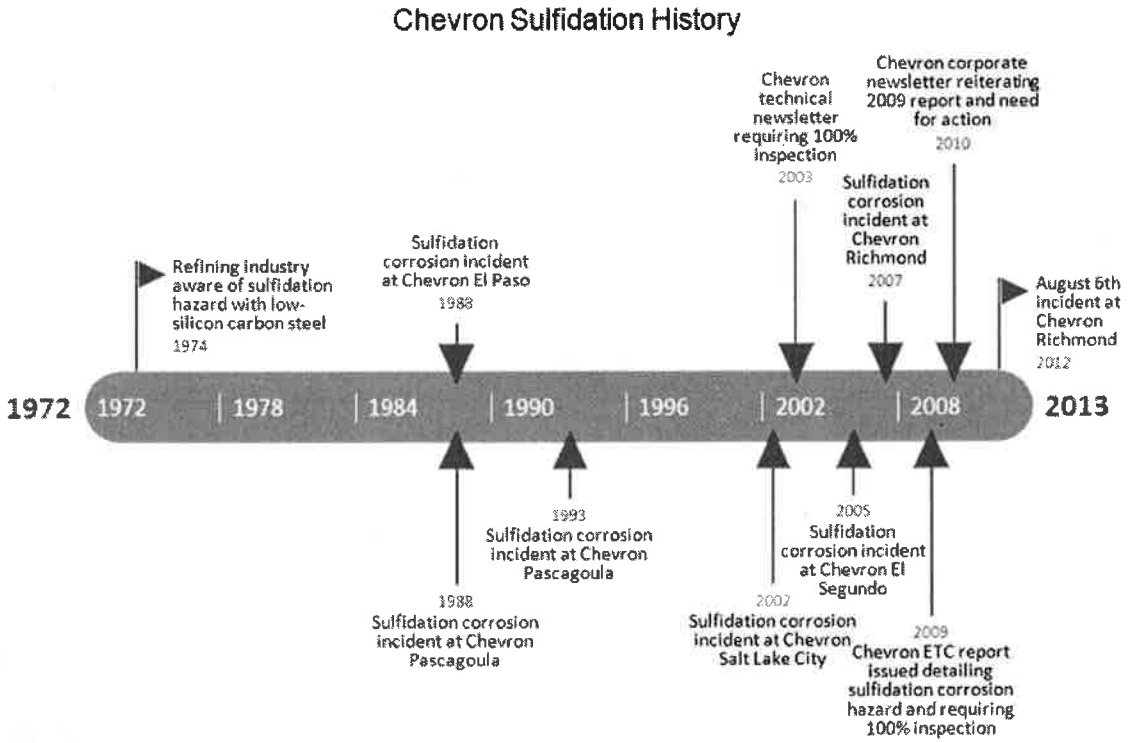

Figure 11. Chevron's key sulfidation events between 1974 and 2013.

[i] The Chevron Energy Technology Company is a separate business unit within the Chevron Corporation that provides technology solutions and technical expertise for Chevron operations worldwide. *See* http://richmond.chevron.com/home/aboutchevronrichmond.aspx (accessed April 4, 2013)

22. Sulfidation experts acknowledged in the Chevron ETC report that, "Until now, Chevron has not directly addressed the risk of low Si[licon] carbon steel..."[i] and that the report lays out a program that "seeks to close these gaps, and to maximize the effectiveness of our inspection." The report clearly indicates that Chevron understood both the potential consequence and the high likelihood of a rupture or catastrophic failure from sulfidation corrosion and calls out Chevron's need for action:

> Sulfidation corrosion failures are not common in Chevron or in the industry but they are of great concern because of the comparatively high likelihood of blowout or catastrophic failure [...] . This can happen because corrosion occurs at a relatively uniform rate over a broad area so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. [...] [S]everal case histories of sulfidation corrosion failures that have occurred in Chevron or in the industry several of which are blowouts.

This Chevron ETC report specifically recommends that inspectors perform 100 percent component inspection on high temperature carbon steel piping susceptible to sulfidation corrosion. However, this 100 percent component inspection program was not implemented at the Richmond refinery prior to the August 6, 2012 incident. The Chevron ETC report defines a priority ranking system to help focus the inspection implementation efforts. The process conditions of the 4-sidecut stream placed it in the highest priority for inspection.

23. Chevron ETC technical experts issued a corporate newsletter in 2010 that again warned of the potential consequence of sulfidation failures. In this newsletter, the 100 percent component inspection recommendation from the 2009 report was reiterated for piping systems such as the crude unit 4-sidecut piping. The newsletter states:

> Sulfidation corrosion failures ... are of great concern because of the comparatively high likelihood of "blowout" or catastrophic failure. This typically happens because corrosion occurs at a relatively uniform rate over a broad area, so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition, the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. Chevron and the industry have experienced numerous failures from this mechanism and recent incidents have reinforced the need for revised inspection strategies and a robust PMI (Positive Materials Identification) program.

[i] A 2003 corporate technical newsletter recommended 100 percent component inspection of carbon steel piping susceptible to sulfidation corrosion following a 2002 Chevron Salt Lake City sulfidation corrosion incident.

The Chevron ETC 100 percent component inspection recommendation for high risk piping systems, established in 2009, was not implemented at Richmond; therefore, the thin-walled low silicon 4-sidecut piping component remained in service until it catastrophically failed on August 6, 2012.

24. Chevron and Chevron ETC metallurgists, materials engineers, and piping inspectors had expertise regarding sulfidation corrosion. They educated personnel and advocated for identification and control of damage mechanisms, including sulfidation corrosion. However, they had limited practical influence to implement their recommendations. These individuals did not participate in the crude unit Process Hazard Analysis (PHA)[i] and did not affect decisions concerning control of sulfidation corrosion during the crude unit turnaround process.[ii]

[i] A process hazard analysis is a hazard evaluation to identify, evaluate, and control the hazards involved in a process. Facilities that process a threshold quantity of hazardous materials, such as the Chevron Richmond refinery, are required to conduct a process hazard analysis per the California Code of Regulations Title 8 Section 5189. Process Safety Management of Acutely Hazardous Materials (1992). PHAs are also required by the California Accidental Release Prevention Program and the federal EPA Risk Management Program.

[ii] The turnaround process includes both the planning stage prior to the shutdown and the activities staged during the shutdown.

Other Significant Sulfidation Occurrences

25. The refining industry has experienced numerous sulfidation corrosion failures, primarily in piping.[28] API RP 939-C identifies 45 sulfidation corrosion failures, one third of which were found to have occurred in carbon steel piping containing low levels of silicon.[29]

26. The August 6, 2012, Chevron Richmond Refinery 4-sidecut pipe rupture was not the first sulfidation corrosion-related incident to occur at a Chevron refinery. In 1988, a low silicon carbon steel (0.02 wt. % silicon) piping component failed at the Chevron's former El Paso Refinery[i] in El Paso, Texas. In addition, two sulfidation corrosion incidents occurred at the Chevron Pascagoula refinery in Pascagoula, Mississippi: one in 1993 and one in 1988 on a low-silicon carbon steel component.

27. In 2002, the Chevron Salt Lake City Refinery experienced a fire when process piping failed as a result of sulfidation corrosion in a low silicon ASTM A53 carbon steel piping component. Chevron communicated the incident throughout the company in a technical newsletter. Chevron experts found that despite regular monitoring of the line for 30 years in compliance with industry standards, their inspection program failed to prevent the failure. Corrosion rates at the unmonitored failure location were found to be five times greater than corrosion rates at the monitored piping locations. The monitored locations were constructed of high silicon ASTM A106 piping (Figure 12). Chevron also found that in the years preceding the failure, both the temperature[ii] and hydrogen sulfide concentration in the process had been increasing. Each of these factors increased corrosion rates and contributed to the failure. In 2003, following this incident, Chevron experts recommended that refineries inspect every piping component (100 % component inspection) in all high-risk piping systems: those operating above 550 °F and containing hydrogen sulfide.

[i] The El Paso Refinery is now owned by Western Refining.

[ii] The temperature in the line had been increased by over 170 °F throughout the life of the unit. During the two years prior to failure, temperatures of the line exceeded the measurement capabilities of the temperature measurement device and so the actual temperature increase cannot be determined.

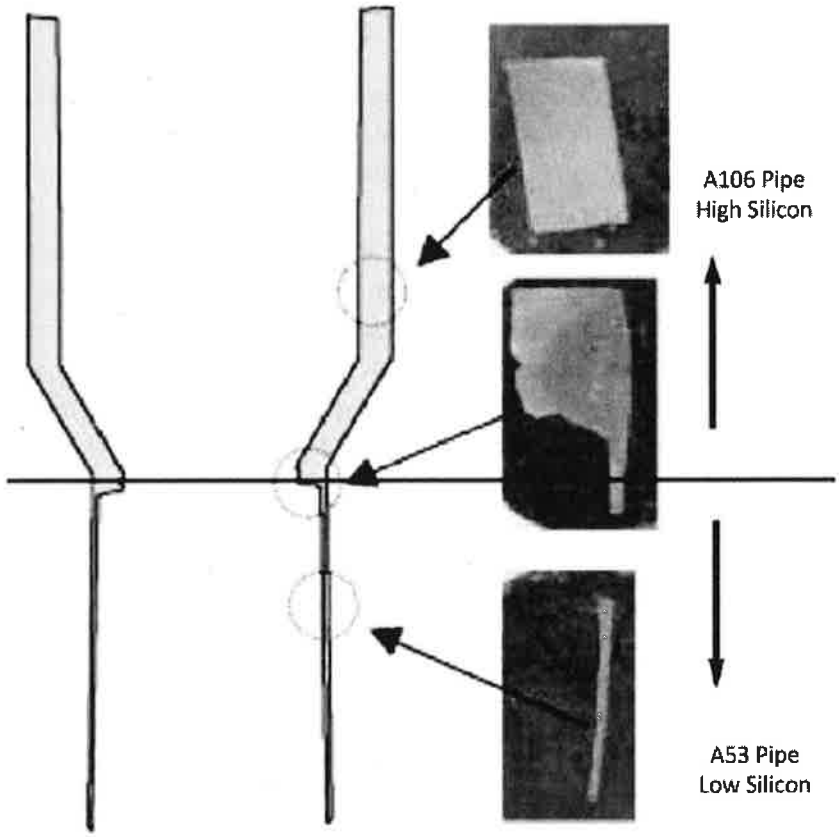

Figure 12. Schematic of failed piping from the Chevron Salt Lake Refinery. Similar to the Chevron Richmond Refinery incident, the failed piping contained low amounts of silicon and corroded significantly faster than adjacent piping components.

28. In January 2007, a failure due to sulfidation corrosion caused a serious fire in the Chevron Richmond Refinery crude unit resulting in a CWS Level 3 alert, initiating a shelter-in-place for the surrounding community. A carbon steel piping spool[i] failed catastrophically during operation (Figure 13). The carbon steel piping contained a low percentage of silicon (<0.005 wt. %). The process fluid ignited, injuring a nearby worker. Chevron informed Contra Costa Health Services' Hazardous Materials Program[ii] (Contra Costa County) in a letter that the metallurgy had been upgraded following this incident as an inherently safer solution. However, the CSB learned that this upgrade was limited to only the immediate piping spool that failed. The inherently safer, more corrosion resistant metallurgy was not implemented more broadly in crude unit high temperature service as a result of this incident.

[i] A piping spool is a small, removable section of piping. In some cases, a piping spool is installed or removed in order to provide a temporary connection or complete disconnection between two piping circuits.
[ii] Contra Costa Health Services' Hazardous Materials program is designed to respond to emergencies and monitor hazardous materials within Contra Costa County. *See* http://cchealth.org/hazmat/ (accessed April 17, 2013).

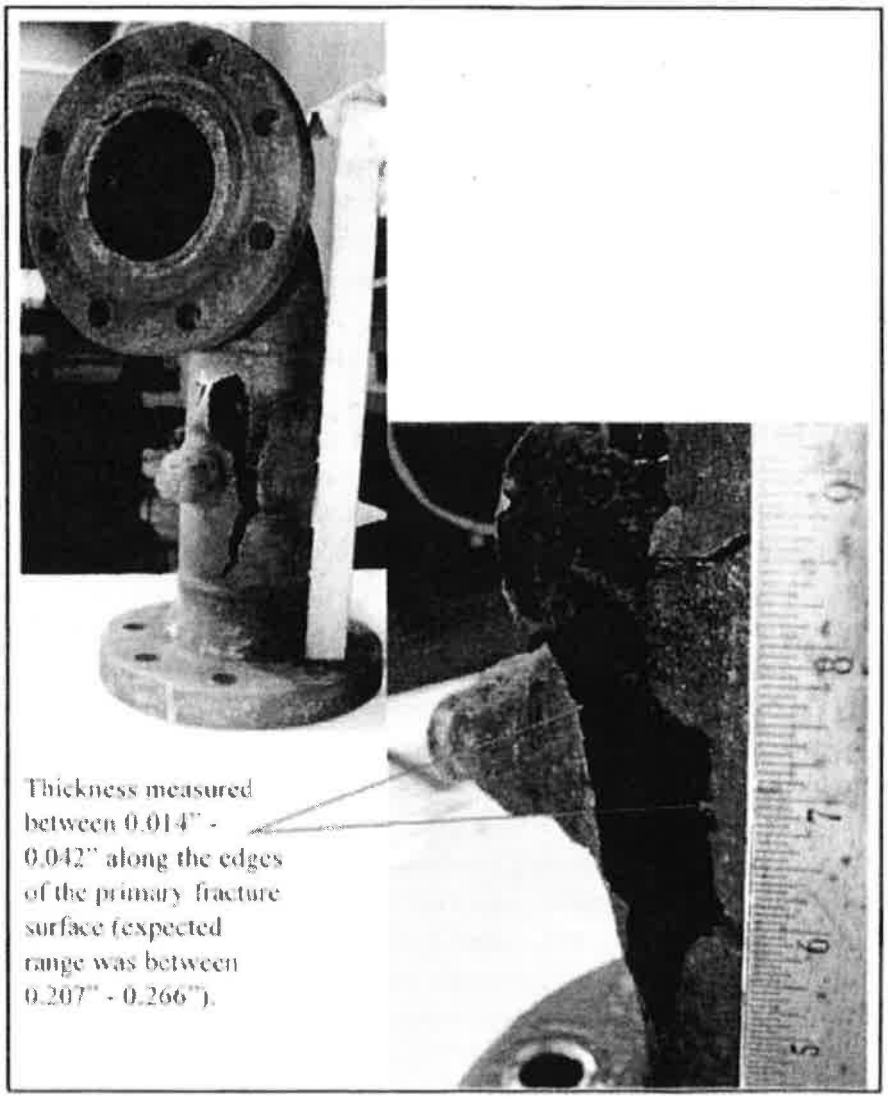

Figure 13. Failed piping component that resulted in the 2007 Richmond crude unit fire. This carbon steel piping was found to contain less than 0.005 percent silicon.

29. Following the August 6, 2012, incident, personnel at the Chevron El Segundo, California, refinery, a near duplicate of the Richmond refinery, inspected their refinery's crude unit 4-sidecut piping. Significant thinning was discovered in the line; the piping from the atmospheric crude column to the pumps was removed and substituted with 9-Chrome, an upgraded and inherently safer material of construction.

30. On November 9, 2009, the Silver Eagle refinery in Woods Cross, Utah, experienced a catastrophic piping failure due to sulfidation corrosion in a 10-inch pipe, while conducting a temporary operation at higher than normal operating temperature. The pipe was located on the

bottom of a reactor in the de-waxing unit. The failed pipe released hydrogen which subsequently exploded, damaging over 100 homes in the nearby neighborhood.

31. On October 6, 2011, an explosion and fire resulted from a catastrophic piping failure at a Canadian refinery in Regina, Saskatchewan, injuring 52 workers. The piping component that failed was substantially thinner than neighboring components. Prior to the incident, the company's inspection data indicated that wall thickness in the overall piping system was within acceptable limits. However, the specific component that failed was not inspected. Although Canadian authorities are still investigating, metallurgical testing has indicated that hydrogen sulfide corrosion contributed to the catastrophic failure.

32. In February 2012, the BP refinery crude unit in Cherry Point, Washington, suffered a failure due to sulfidation corrosion, causing a large fire. This incident demonstrates that even when applying inherently safer concepts to reduce the potential for major hazards, it is still vital to fully understand all processes and piping configurations and incorporate a rigorous inspection program. The piping that failed was constructed of 9-Chrome. The line was used only during start-up operations and otherwise remained in-service and non-flowing. Such lines that do not have regular process flow yet remain in contact with process fluids are commonly referred to as "dead legs." The failure location was a high-point in the piping connected to the top of an operating process line. Hydrogen sulfide evolved from the process fluid and collected in the 9-Chrome piping. The concentrated vapor-phase hydrogen sulfide severely corroded the 9-Chrome, causing the failure. CMLs were located on adjacent elbow components; however, no CMLs were placed on the straight-run piping component where the failure occurred. The Cherry Point sulfidation failure demonstrates that even with more corrosion-resistant, inherently safer metallurgy, failure from sulfidation corrosion still may occur if piping is not effectively inspected or piping configurations are not adequately evaluated. In addition it is important to conduct a thorough analysis to determine the best material of construction for the process conditions.

Process Hazard Analysis

33. Chevron personnel analyze numerous deviations[i] for each portion of a process when conducting a Process Hazard Analysis (PHA). These include conditions such as changes in flow and temperature and pressure extremes. Specifically of interest, one of the deviations analyzed was "leak/rupture" of the particular vessel or pipe. For each deviation, the team's responsibility was to identify causes, consequences, safeguards, and recommendations. The 4-sidecut line was analyzed in the most recent crude unit PHA. Corrosion was *not* identified as a potential cause of a leak/rupture in the piping (emphasis added).

34. Sometimes referred to as a corrosion review, a damage mechanism hazard review analyzes risks presented by all process failure mechanisms such as corrosion and cracking. Common process failure mechanisms are described in API 571: *Damage Mechanisms Affecting Fixed Equipment in the Refining and Petrochemical Industries*.[30] Such a review ensures that potential hazards caused by process conditions, process materials, and external mechanisms are properly identified, analyzed, and systems are put in place to control or eliminate the hazard. Despite Chevron knowledge and expertise of potential damage mechanisms (such as sulfidation corrosion), the CSB found these hazards are only identified in a PHA if the participants conducting the PHA happen to have personal knowledge of the relevant mechanism. The Chevron PHA teams do not typically seek assistance from corrosion experts.[ii] The inclusion of a damage mechanism hazard review as part of the PHA is not required by the state of California, the California Division of Occupational Safety and Health (Cal/OSHA),[iii] Contra Costa County, the City of Richmond,[iv] or Chevron standards. Because Chevron does not conduct, and is not required to conduct, a formal damage mechanism hazard review, damage mechanisms are only identified when the PHA team happens to have some knowledge of the mechanism. As a result, many damage mechanisms which occur in various processes are not properly addressed.

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[i] Deviations using guide words (such as no, more, less, as well as) and process parameters (such as flow, pressure, temperature) are analyzed in PHAs. *See* Center for Chemical Process Safety (CCPS). "Guidelines for Hazard Evaluation Procedures." 2nd ed., Page 132, 1992.

[ii] The Crude Unit Business Improvement Network (BIN) Leader, a crude unit expert, reviews portions of the PHA with the PHA team. However, this review did not identify the potential for sulfidation corrosion failures in the 4-sidecut piping. A rigorous review of corrosion and damage mechanisms present in the crude unit was not performed during the PHA process.

[iii] The state of California, under an agreement with the federal Occupational Safety and Health Administration, or OSHA, operates an occupational safety and health program in accordance with Section 18 of the Occupational Safety and Health Act of 1970. *See* http://www.osha.gov/dcsp/osp/stateprogs/california.html (accessed April 17, 2013). The Department of Industrial Relations administers the California Occupational Safety and Health Program, commonly referred to as Cal/OSHA. The program applies to all public and private sector places of employment in the state, with some exceptions. *See* http://www.dir.ca.gov/dosh/dosh1.html (accessed April 17, 2013).

[iv] The City of Richmond adopted an ordinance on Industrial Safety, Richmond Municipal Code Chapter 6.43 (also known as the RISO), on December 18, 2001, "for the purposes of protecting public health and safety by prevention of accidental release of hazardous materials and to assure protection of the environment." Richmond Municipal Code §6.43.040 (February 5, 2013). There are two facilities, including Chevron, that are located in the City of Richmond and subject to this ordinance. More information about the RISO is provided later in the report.

35. During a hazard analysis process such as a PHA, the evaluation team has to determine the likelihood of a hazardous consequence occurring. Then the team must identify safeguards which will reduce the risk of the hazard to an acceptable level. A recognized methodology for consistently and objectively making these determinations could include the use of quantitative, semi-quantitative, or qualitative tools.[31] Chevron does not employ a prescribed methodology for determining the likelihood that an incident will occur or whether a safeguard will be effective. Instead, Chevron relies upon the judgment of the people on the PHA team, who base their conclusions upon their collective experiences, beliefs, and areas of expertise. In its 2009 crude unit PHA, Chevron simply cited non-specific, judgment-based qualitative safeguards such as: utilizing metallurgy to minimize corrosion, having effective maintenance and inspection programs, and providing pipe wall corrosion allowances.[i] The effectiveness of these safeguards was neither evaluated nor documented; instead the safeguards were merely listed in the PHA. Had the adequacy of these safeguards been verified, improved safeguards intended to protect against sulfidation-induced failure of carbon steel piping could have been recommended.

36. Following the August 6th incident, Cal/OSHA inspected the Chevron facility and issued citations. Only one citation related to PHAs, and it was not associated with evaluating the effectiveness of safeguards. Rather, the emphasis was that Chevron's PHA did not adequately account for hazards caused by other units associated with the crude unit. The citation stated "The Employer [Chevron] failed to perform an effective Process Hazard Analysis [PHA] of the crude unit. Specifically, it failed to identify, evaluate, and control potential hazards caused by upstream and downstream units that provide and receive feed from the crude unit."[32] Had the Cal/OSHA regulation required documentation of the effectiveness of safeguards, Chevron would have been obligated to conduct this analysis and Cal/OSHA inspectors could rely on the regulation for support during inspections.

[i] Corrosion allowance refers to extra wall thickness added as a safety factor to the design of a piece of equipment beyond that needed solely for mechanical considerations such as design temperature and pressure. This extra thickness is provided to accommodate for expected loss of wall thickness due to corrosion over the life of the equipment.

Operational Changes

37. The original design of the 4-sidecut circuit included equipment which had the effect of removing dissolved hydrogen sulfide, the most aggressive sulfur compound associated with sulfidation corrosion, from the 4-sidecut light gas oil process fluid. As a result, the 4-sidecut equipment was effective in reducing the sulfidation corrosion rate. This allowed the 4-sidecut equipment to be constructed of carbon steel. In 1991, this 4-sidecut equipment was taken out of service. No management of change[i] (MOC) was performed to analyze the effect of the elimination of this hydrogen sulfide-removing equipment on 4-sidecut corrosion rates. Such an MOC would have ensured that the increase in sulfur concentration on the carbon steel 4-sidecut piping was reviewed prior to removing the equipment.

38. Crude oil feedstock used at the Chevron Richmond Refinery is obtained from a variety of different sources that are blended before processing. These various crudes have different compositions, such as varying sulfur compounds and concentrations. These crudes can have differing corrosion effects on process equipment and piping. There is an increasing trend in crude oil refining to process less expensive "opportunity crudes" because they can provide significant cost savings to the company.[ii] However, these crudes may contain more undesirable characteristics such as high sulfur content, high naphthenic acid content, or very heavy hydrocarbons[33] that a refinery may not have been originally designed to process. Refinery equipment may not be the proper material of construction to achieve the design life of the equipment when exposed to the different operating conditions. Additional mitigation may be needed to reduce risk. In 1984, the Chevron Richmond Refinery crude oil feed contained approximately 85 volume % Alaskan North Slope (1 wt. %) crude oil. As the refinery began running more high-sulfur content crudes, the sulfur content in the 4-sidecut line steadily increased (Figure 14), as discussed below.

[i] Management of change requires that employers have procedures to manage changes to process chemicals, technology, equipment, and procedures. The procedures must address the technical basis for the change, the impact on safety and health, and training required for employees affected by the change.

[ii] Crude oil costs can account for up to 90% of the operating costs in a refinery. *See* Qu, Dingrong, Xiaohui Liu, Xiu Jiang, Zhenggui Lan, and Guangbin Shan. "Setting Critical Operational TAN and Sulfur Level for Crude Distillation Units." *Corrosion 2011 Conference & Expo.* Paper No. 11362. NACE International, 2011.

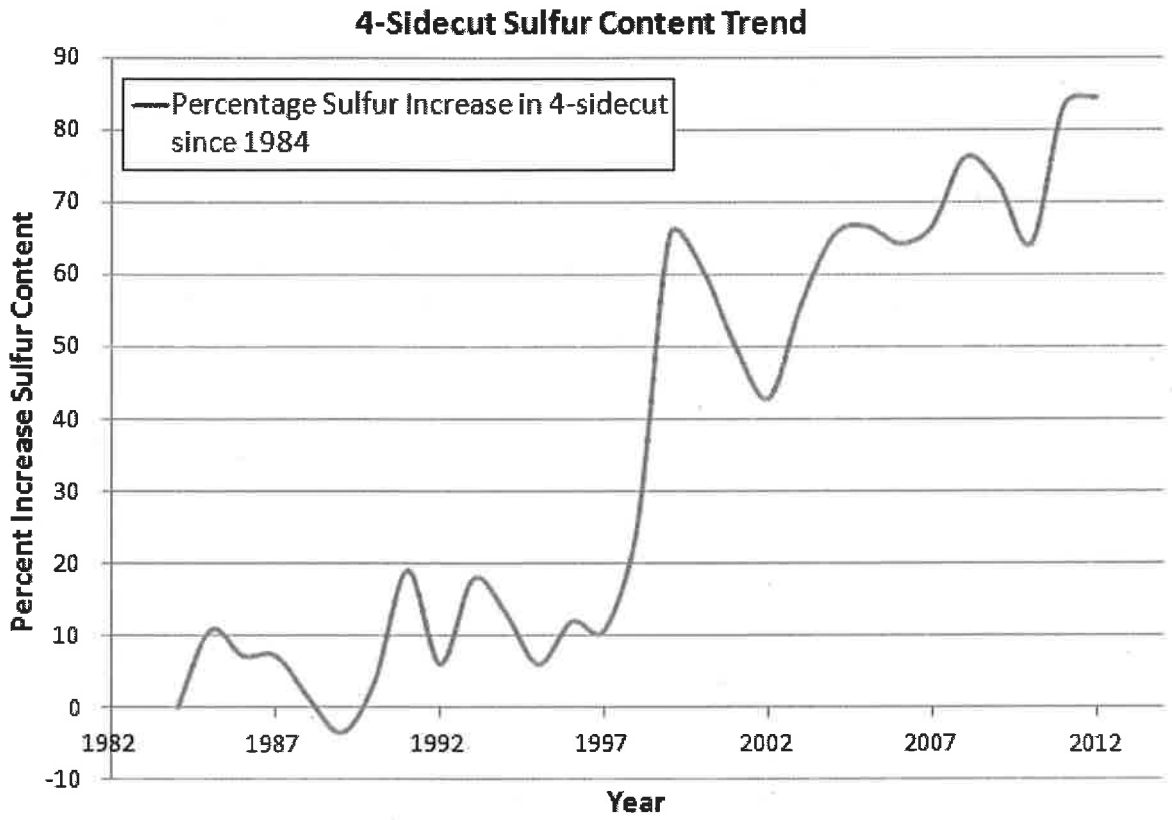

Figure 14. Graph shows the percentage increase from 1984 values of the sulfur content in the 4-sidecut.

39. When Chevron introduces a new crude, an MOC is generated to evaluate the potential impact on the refinery.[i] While Chevron stayed under its established crude unit design basis for total wt. % sulfur of the blended feed to the crude unit, the sulfur composition significantly increased over time. Historic data indicates that the sulfur in the 4-sidecut stream has increased from 0.8 to 1.6 wt%. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line. Chevron did not conduct an MOC analyzing the impact that increases in sulfur composition would have on corrosion in the crude unit. Chevron also did not change its corrosion monitoring programs in response to the increased sulfur content.

40. The CSB found that increased Chevron Richmond usage of non-domestic crude feed stock over time resulted in higher sulfur content in the process fluid passing through the 4-sidecut piping. Specifically, the percentage of sulfur in the Richmond refinery crudes increased nearly 85% between 1984 and 2012, including a significant jump of 32% from 1998 to 1999. This increase in sulfur content corresponded with a simultaneous increase in the usage of non-domestic crude feed at the Richmond refinery.

[i] Chevron MOCs on new crudes considered general operational issues but did not analyze corrosion effects from sulfidation corrosion.

41. Sulfidation corrosion rates increase in piping circuits as temperature and sulfur content increase. Accordingly, the 4-sidecut sulfidation corrosion rate increased between 1984 and 2012 due to the increase in sulfur content in the line. The CSB found that for the 26-year period from the installation of the piping in 1976 through 2002, the 52-inch 4-sidecut component had lost approximately 33 percent of its wall thickness. From the single inspection of the 52-inch component in 2002 to the incident in 2012 – just ten years – an additional 57 percent of the original component nominal wall thickness was lost near the rupture location due to sulfidation corrosion.[i] In addition to the sulfur content increase, the 4-sidecut draw temperature increased from 625 °F in 1992 to 680 °F in 2002. Corrosion rates and remaining life calculations based on past sulfur content and temperatures may not accurately reflect current corrosion rates if process conditions have changed. Inspection based on historical corrosion rates may be too infrequent to detect an increase in corrosion caused by adverse changes in process conditions, potentially leading to equipment failure.

42. API RP 939-C states that refinery feed stock changes reduce the relevance of past inspection data when predicting future corrosion rates:

> Oil refineries that processed a consistent diet of a particular crude oil or crude blend could often base future predictions on past experience. However, over the past 20+ years, global economics have resulted in many refineries processing tens of different crudes in any given year; thus, minimizing the accuracy, or even feasibility, of predictions based on historical data. Additionally, the verification of the actual corrosion rate experienced while processing a specific crude oil is very difficult.[34]

43. API 570 *Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems*, the API standard for inspecting piping, recommends companies to incorporate process changes into inspection programs. The standard states:

> The owner/user is … responsible for implementing an effective MOC process that will review and control changes to the process and to the hardware. An effective MOC process is vital to the success of any piping integrity management program in order that the inspection group will be able to anticipate changes in corrosion or other deterioration variables and alter the inspection plan to account for those changes. The MOC process shall include the appropriate materials/corrosion experience and expertise in order to effectively forecast what changes might affect piping integrity. The inspection group shall be involved in the approval process for changes that may affect piping integrity.

[i] The 4-sidecut 52-inch component had an original wall thickness of 0.322 inches. Metallurgical analysis found the thinnest portion of the 52-inch 4-sidecut component was 0.03 inches.

> *Changes to the hardware and the process shall be included in the MOC process to ensure its effectiveness* [emphasis added].[35]

Chevron failed to comply with the requirements of API 570 when it did not conduct an MOC to thoroughly evaluate the change of increasing sulfur weight percentage in crude oil feed and to assess how it might affect corrosion rates within the 4-sidecut piping circuit. After the August 6, 2012, incident, Cal/OSHA inspected the Chevron Richmond Refinery and issued citations.[1] However, Cal/OSHA did not issue any citations for failing to perform an MOC when sulfur composition in the crude oil feed was increased.

Chevron Sulfidation Corrosion Inspection and Mitigation

44. In the ten years prior to the incident, a small number of Chevron personnel with knowledge and understanding of sulfidation corrosion made at least six recommendations (listed in the following six paragraphs and included in Figure 15) to increase inspections or upgrade the metallurgy in the 4-sidecut piping. The recommendations made by these personnel were not implemented by Chevron management.

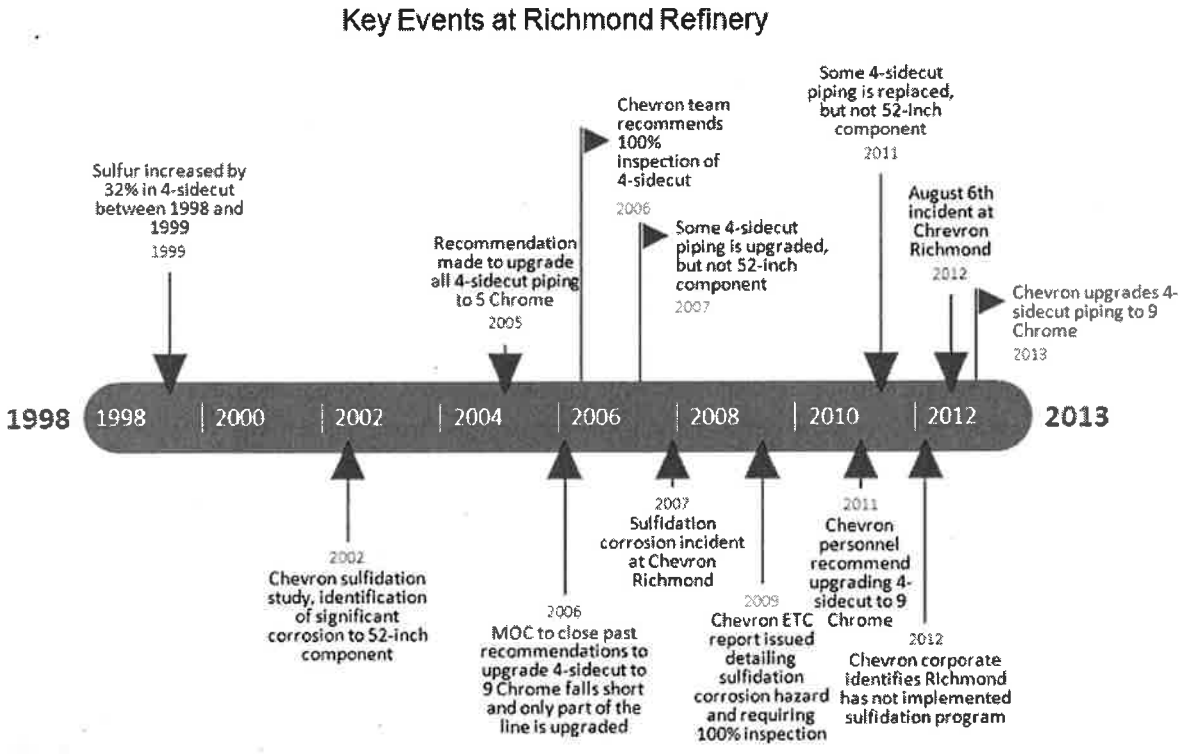

Figure 15. Key events at the Richmond refinery between 1998 and 2013.

[1] Cal/OSHA citations issued January 30, 2013.

45. In August 2002, a Chevron Richmond Refinery employee performed a study analyzing sulfidation corrosion rates in the crude unit and identifying potentially vulnerable areas. The employee discovered that the 4-sidecut operating temperature had been increased and concluded that this increase would cause more hydrogen sulfide to evolve, leading to increased sulfidation corrosion rates. As a result of these findings, the employee recommended increased inspection of the 4-sidecut piping and noted that this piping might need to be upgraded from carbon steel to 5-Chrome, a steel alloy that is more resistant to sulfidation corrosion. In 2002, proactively following up on this study, the crude unit inspector conducted additional piping inspection and identified accelerated corrosion in the 52-inch 4-sidecut component. The inspector recommended upgrading this piping during the next shutdown in 2007. In the inspector's 2002 accomplishments, Chevron management acknowledged this effort to prevent a significant incident; it was characterized as "a save." However, during the 2007 turnaround the recommendation was not implemented, and because a CML was not added to the inspection program, the 52-inch component was not inspected after 2002.

46. In February 2006, a team consisting of a materials and corrosion engineer, an inspector, a process engineer, a metallurgist, and a design engineer issued a Corrosion Mitigation Plan for the Chevron Richmond Refinery crude unit. The report specifically identified the 4-sidecut piping to be at risk for high temperature sulfidation corrosion. The report described that low silicon carbon steel can corrode faster than carbon steel manufactured with higher silicon content, and recommended that 100 percent inspection be performed on the 4-sidecut line using continuous monitoring technology. During the 2007 crude unit turnaround, continuous monitoring probes were only installed on a segment of the 4-sidecut line that did not include the 52-inch component that ultimately failed. The 100 percent inspection recommended in the 2006 Corrosion Mitigation Plan was not performed.

47. During the 2007 turnaround, the crude unit inspector recommended that the refinery upgrade the entire 4-sidecut piping with 5-Chrome. The recommendation was based on findings obtained during the 2002 crude unit turnaround, where the crude unit inspector found that the 52-inch 4-sidecut component had lost one-third of its wall thickness due to corrosion. However, after evaluation, this recommendation was not accepted by the turnaround planning team. Basing its decision on limited inspection data, Chevron determined that the 8-inch portion of the 4-sidecut piping that ran from the atmospheric column to the pump, the portion which included the 52-inch component, had sufficient wall thickness to last to the next turnaround scheduled for Fall 2011.[i] The piping downstream of the pump, which operates at a higher pressure, was determined not to have sufficient wall thickness to last to the next turnaround. This piping was removed and replaced with 9-Chrome, an upgraded and inherently safer metallurgy. The 52-inch component of the 8-inch piping between the atmospheric column and the pump was not replaced during the 2007 turnaround even though it had been identified as thinned in 2002.

[i] This decision was made without reinspecting or evaluating the thickness of the thinned 52-inch component identified in 2002 that prompted the recommendation.

Furthermore, a permanent CML was not placed on the 52-inch component, and it was not entered into the inspection database. As a result, the component was not inspected again.

48. In September 2009, Chevron ETC corrosion experts released a formal technical report discussing sulfidation corrosion and the specific issues associated with carbon steel, including the potential for high corrosion rates in carbon steel piping containing low percentages of silicon. In its report, Chevron ETC issued recommendations for inspection and provided guidelines for prioritizing piping circuits susceptible to sulfidation corrosion so that high-risk lines could be evaluated first. It was recommended that 100 percent component thickness testing be completed on all high priority lines one time to identify thin, low-silicon components to establish a baseline of corrosion rate and risk for failure. Following the release of the report, the Chevron Richmond Refinery materials group completed the risk-ranking of the carbon steel piping in the Richmond Lube Oil Project (RLOP) and in the crude unit, two units known to be susceptible to sulfidation corrosion. The group identified the crude unit 4-sidecut line as a high risk line per the report ranking guidance. Instead of completing the 100 percent component inspection, the 4-sidecut was recommended for replacement with 9-Chrome. However, the replacement recommendation was denied because the available, limited inspection data indicated the piping would last until the next turnaround. Subsequently, the alternative 100 percent component inspection was also never performed.

49. Five months prior to the incident in March 2012, a Chevron corporate review of Richmond identified that inspection of all carbon steel components susceptible to sulfidation corrosion was not being performed at the Richmond refinery. In addition to identifying that CMLs were not in the proper locations, this corporate review found that critical inspection recommendations were being submitted to the shutdown planning process, but were being denied. Chevron corporate identified that Richmond refinery leadership needed to review and implement the 2009 Chevron ETC report recommendations.

50. Chevron conducts "Intensive Process Reviews" prior to turnarounds. This process involves knowledgeable individuals including Business Improvement Network leaders, process engineers, metallurgical engineers, design engineers, and turnaround planners. The purpose of the review is to identify key unit issues that should be addressed and repaired during the unit turnaround. Prior to the 2011 crude unit turnaround, Chevron personnel conducted an Intensive Process Review of the crude unit and specifically recommended that the 4-sidecut carbon steel piping "should be upgraded to 5 Cr [5-Chrome]… due to sulfidation." Although the Intensive Process Review identified sulfidation problems in the 4-sidecut line, this activity was ineffective. The 4-sidecut piping was not upgraded during the 2011 crude unit turnaround.

51. In preparation of the work list for the 2011 crude unit turnaround, the crude unit inspector and crude unit metallurgist recommended that the 4-sidecut line be replaced with an upgraded metallurgy, 9-chrome, the metallurgy recommended in the Chevron new construction guidelines for piping in high temperature and high sulfur service. The recommendation was based on the

high priority ranking of the 4-sidecut line, corrosion history, and both Chevron and industry recommended best practice. However, the turnaround management team determined that the inspection data available for the 4-sidecut piping, from CMLs on elbow components which are less prone to sulfidation corrosion, did not support a material upgrade during the 2011 turnaround.[i, ii] The lack of data on the more susceptible 4-sidecut straight-run piping components was not considered.

[i] This decision was made without reinspecting or evaluating the thickness of the 52-inch component identified in 2002.

[ii] A portion of the 4-sidecut 12-inch line was replaced during the 2011 turnaround with carbon steel due to thinning caused by sulfidation corrosion.

Inherently Safer Systems

52. The Center for Chemical Process Safety (CCPS) is a corporate membership organization that identifies and addresses process safety needs within the chemical, pharmaceutical, and petroleum industries.[36] Chevron is a corporate member of CCPS.[37] The CCPS book *Inherently* Safer *Chemical Processes, 2nd ed.* defines inherently safer design as the process of identifying and implementing inherent safety in a specific context that is permanent and inseparable.[38] In the book *Guidelines for Engineering Design for Process Safety, 2nd ed.*, CCPS states "inherently safer design solutions eliminate or mitigate the hazard by using materials and process conditions that are less hazardous."[39]

53. Inherently safer technologies are relative; a technology can only be described as inherently safer when compared to a different technology with regard to a specific hazard or risk.[40] A technology may be inherently safer with respect to one risk but not safer from another risk. For this reason, it is important to carry out a comprehensive, documented hazard analysis to determine the individual and overall risks in a process and assess how the risks can be effectively minimized to control hazards. An inherently safer systems review details a list of choices offering various degrees of inherently safer implementation. The review should include risks of personal injury, environmental harm, and lost production, as well as evaluating economic feasibility.[41]

54. It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating.[42] Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts. Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce risks is an important step in implementing an inherently safer process. Chevron training programs on inherently safer systems reflect this approach, stating "we have the greatest opportunity to eliminate or minimize hazards during the development phase of new projects or major revamps of existing facilities."

55. After a 2007 incident caused by a pipe failure in the Richmond refinery crude unit, Chevron implemented an "Inherently Safer Solution" by upgrading the piping to metallurgy that was less susceptible to sulfidation corrosion. However, the change was implemented intuitively without a supporting inherent safety review or failure mechanism hazard review to provide a detailed documented technical rationale for the metallurgy selection. Without such a review, the material selected cannot be analyzed to determine if it is the best inherently safer solution for the process in order to minimize risk.

56. Following the August 6, 2012, incident, the 4-sidecut piping circuit at the Richmond refinery was upgraded from carbon steel to 9-Chrome.[i] However, Chevron did not produce a documented inherently safer hazard review before commencing the rebuild of the crude unit. The crude unit at the Chevron El Segundo refinery is nearly identical in construction and design to the Richmond refinery crude unit. Chevron informed the CSB that piping *downstream* of the 4-sidecut pumps in the 4-sidecut piping circuit at the El Segundo refinery was upgraded in 2001[ii] from carbon steel to stainless steel. As stated previously, after the August 6, 2012, Richmond incident, the 4-sidecut piping *upstream* of the 4-sidecut pumps at the El Segundo refinery was upgraded from carbon steel to 9-Chrome. Had a comprehensive inherently safer systems review been conducted at the Richmond refinery following the August 6th incident, a different metallurgy, such as stainless steel which was installed at the Chevron El Segundo Refinery, may have been identified as inherently safer than 9-Chrome with respect to sulfidation corrosion.

57. An effectiveness ranking of techniques used to control hazards and the risk they represent can be described as a hierarchy of controls. The further up the hierarchy, the more effective the risk reduction achieved (Figure 16). All concepts in the hierarchy of controls should be included in the process of risk assessment and reduction. Upgrading metallurgy to a more corrosion resistant material may be a high ranking, inherently safer choice for certain corrosion mechanisms, such as sulfidation corrosion. Holding other variables constant, upgrading the material of construction may reduce the severity of corrosion and the likelihood of a failure.

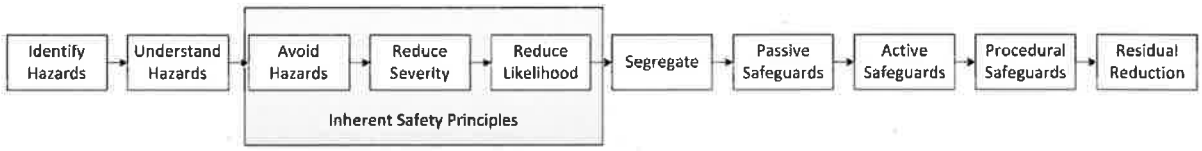

Figure 16. Hierarchy of controls. The boxes reflect inherently safer controls from left to right, based on *Process Plants: A Handbook for Inherently Safer Design Second Edition*; Kletz, Trevor Amyotte, Paul; CRC Press 2010.

58. Chevron employees have recommended implementing inherently safer designs through the MOC process, incident investigations, technical reports, and recommendations from employees in the past. However, the CSB has not identified any documented, thorough analysis of the proposed inherently safer solutions. In addition, Chevron has repeatedly failed to implement proposed inherently safer recommendations. For example, following the discovery of significant 4-sidecut piping sulfidation corrosion in 2002, a Chevron inspector issued the following recommendation to replace the piping in the 2007 turnaround:

[i] After the 2012 incident, the Richmond refinery stated that stainless steel was susceptible to chloride stress corrosion cracking and should not be used.
[ii] Chevron verbal estimate for date of piping installation. No MOC was conducted to review and document this change.

INFORMATION

> The #4 sidecut piping from C-1100 to P-1149/A to E-1113 was RT (x-ray) inspected for hot H2S [sulfidation] corrosion. The piping is actively corroding, particularly on the section on the discharge line from the pumps near the exchanger; the line upstream of the P-1149/A pumps is corroding as well. Corrosion rates indicate that the piping has 4 years of remaining life until the refinery throwaway thickness of 0.14" [inch] is reached. The carbon steel piping is currently running at temperatures between 650 °F on the pump suction line to 641 °F on the line just before E1113; the upper limit for carbon steel piping in this service is 550 °F. A materials upgrade to 5 chrome would raise the upper limit to between 650-750 °F. Additionally, the ABCR piping loop from the same sidecut draw line off of the column to P-1148/A to E-1111 is also carbon steel and operates at the same temperatures, rendering the ABCR piping system to E-1111 susceptible to hot H2S corrosion as well.

Recommendation

> Replace the existing #4 sidecut piping noted above from C-1100 through P-1149/A to E1113 and P-1148/A to E-1111 (approximately 700'[feet] of 12", 10", 8" and 6"piping, plus some 4"and 3" at the P-1149/P-1148 suction/discharge headers). Upgrade the pipe material from carbon steel to 5 chrome.

To implement this recommendation, Chevron initiated an MOC in 2006 to replace the piping during the 2007 Turnaround. However, the MOC supporting documents had a narrowed scope to only replace the section of piping from P-1149/A pumps to the E-1113 heat exchanger because Chevron reduced the work scope during the 2007 turnaround planning process. The Description of Change in the MOC stated:

> Existing line is carbon steel in a hot service that operates in the range where high temperature sulfadation [sic] occurs. The line has been ut[i] inspected and found to be nearing tmin[ii] requiring replacement. Due to the higher temperature 9CR [9-Chrome] would be the prefered [sic] material.

Contradicting this Description of Change detailing a replacement of the entire 4-sidecut piping circuit, the MOC Summary Review and attached documentation only authorized replacement of the piping from the P-1149's to E-1113. The MOC states:

[i] UT is an abbreviation used to indicate ultrasonic thickness testing inspection technique.
[ii] Tmin is an abbreviation used to indicate minimum required piping wall thickness.

> 4 S/C piping has been operating hotter in recent years. The hotter temperatures 550 °F are in the high temperature sulfadation [sic] range. Additionally the section of 4 S/C piping from P-1149' s to E-1113 has been found to be nearing tmin.
>
> The section of pipng [sic] from P-1149's to E-1113 will be replaced with 9 Cr [9-Chrome] piping.

As a result, the portion of the piping containing the 52-inch component that failed on August 6th remained in service. Although the recommendation was intended to more broadly apply inherently safer materials of construction, the final implementation by the MOC limited the application of this more corrosion resistant metallurgy.[i] Again, the inherently safer, more corrosion resistant, metallurgy was not implemented more broadly in crude unit high temperature service. Other examples are discussed above in the section entitled *Chevron Sulfidation Corrosion Inspection and Mitigation.*

59. In 2007, the Chevron Richmond Refinery conducted training to teach employees about the importance of complying with the City of Richmond's Industrial Safety Ordinance (RISO)[ii] inherent safety guidance. The training states "we should always strive to implement inherently safer strategies to the greatest extent feasible." However, Chevron did not regularly or rigorously[iii] apply inherently safer design strategies in opportunities including PHAs, MOCs, incident investigation recommendations, and during turnarounds.[iv]

60. Chevron uses an inherently safer design checklist[v] for PHAs to meet inherently safer systems analysis requirements of the RISO. The checklist, provided by Contra Costa County, is intended to aid identification of opportunities to implement inherently safer design during the PHA process. The checklist was intended to stimulate discussion and analysis of potential opportunities to implement inherently safer design. Contra Costa County's guidance on the IST checklist states that some items may need to be reviewed by a team that is outside the PHA team in order to involve people with the required expertise. Chevron utilized the Contra Costa County inherently safer technologies checklist (IST Checklist) during the 2009 crude unit PHA.

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[i] As discussed earlier, only the section of piping downstream of the pumps was replaced with 9-Chrome.
[ii] The RISO will be discussed in more detail in the *Regulatory Oversight* section below.
[iii] Chevron does not utilize inherent safety guidewords or checklists during the MOC or incident investigation process. Inherently safer guidewords help direct the inherently safer review process. Examples of guidewords include minimization, substitution, moderation, and simplification. These words may be applied to materials, product inventory, process controls, process piping, and siting, among others. *See* Center for Chemical Process Safety (CCPS). "Inherently Safer Chemical Processes – A Life Cycle Approach." 2nd ed., Table 8.3, 2009.
[iv] As stated in the *Regulatory Oversight* section below, Chevron is only required to conduct inherently safer design strategies during PHAs and for the construction of new processes.
[v] Contra Costa County's guidance document entitled "Attachment C: Inherently Safer Systems Checklist" is provided as a tool for facilities to utilize during the PHA process. The actual use of the checklist is not required. *See* http://cchealth.org/hazmat/pdf/iso/attachment_c.pdf (accessed April 17, 2013).

However, only three permissively worded[i] inherently safer system recommendations were made, none of which addressed sulfidation corrosion or piping metallurgy. In addition, Chevron performed the checklist analysis using the same individuals who conducted the PHA despite Contra Costa County's guidance to involve other personnel with additional expertise. Performing a superficial analysis, Chevron failed to adequately consider inherently safer systems like improved metallurgy for corrosion resistance. For instance, the checklist prompted: "Use corrosion resistant material?" In response, Chevron stated that "vessel specifications and piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service." No mention is given to improving metallurgy to reduce corrosion. There is also no documented analysis regarding potential materials with enhanced corrosion resistance. There was no documentation of the inherently safer technologies analysis, and no inherently safer alternatives were documented. The checklist as applied by Chevron was a "check-the-box" exercise. Chevron Richmond PHAs were thus not an effective means of driving inherent safety. The table below gives a sample of the IST checklist questions along with the associated Chevron responses.[ii]

Contra Costa County Checklist Question	**Chevron IST Analysis**
Use Corrosion resistant materials?	Vessel specifications and piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service.
Use smallest diameter piping?	Piping sizes are the smallest possible for the capacity of the unit.
Substitute less hazardous raw materials?	Raw materials in use are of minimal hazard.
Dilute hazardous raw materials?	Raw materials currently dilute where applicable.
Minimize off-site impacts?	#4 Crude Unit is located at a distance from public areas.
Easy operation of valves designed to prevent inadvertent error?	In general, valves are arranged in a logical manner.
Increasing wall strength?	Piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service.

61. Contra Costa County inspected the Chevron Richmond Refinery in 2011, auditing Chevron's implementation of the county's inherently safer systems analysis requirements in the PHA process. The inspectors determined that Chevron's PHAs "follows the requirements specified by … ISS [inherent safety systems] guidelines." This approval by Contra Costa County

[i] All began with "consider" and two began with "consider evaluating" which does not require any action by Chevron.

[ii] The comprehensive list of IST checklist questions and Chevron's corresponding answers are provided separately on the CSB website.

conveyed to Chevron that the regulator considered that Chevron's minimal analysis of opportunities to implement inherently safer design, its "check-the-box" exercise, was sufficient.

62. Effectively implementing inherently safer technology provides an opportunity for preventing major chemical incidents. The August 6, 2012, incident at Chevron and other incidents[43] throughout the refining industry highlight the difficulty in preventing failure caused by sulfidation corrosion in low silicon carbon steel piping solely through inspection, a procedural safeguard that is low on the hierarchy of controls. Using inherently safer design concepts to avoid issues such as variation in corrosion rate in carbon steel piping due to hard-to-determine silicon content will reduce future similar failures in refineries. Chevron and other process plants' implementation of inherently safer systems to the greatest extent feasible would provide a higher degree of protection from incidents like the one that occurred on August 6, 2012.

63. It is essential that MOCs incorporate hazard analyses and the assessment of opportunities to implement inherently safer systems. This process can be assisted through the use of guidewords to trigger the thought process. CCPS states that "by including inherent safety guidewords in a management of change program, the MOC protocol recognizes inherent safety as both a driving force for - and as an opportunity during - implementation."[44]

64. Layer of Protection Analysis (LOPA) is a well-recognized hazard analysis methodology that is intended to determine if a sufficient number of safeguards or layers of protection exist to protect against a particular hazard or accident scenario.[45] As the potential consequence of a particular scenario increases, the number of safeguards or protection layers must increase to reduce the risk of the scenario to what is considered an acceptable or tolerable level.[46] LOPA can be used to help an organization decide if the risk of a scenario or hazard has been reduced to a level that is "as low as reasonably practicable" (ALARP).[47] ALARP is a risk reduction goal, where risk reduction efforts are continued until the incremental effort to further reduce risk becomes grossly disproportionate to the level of additional risk reduction.[48] By rigorously reviewing accident or hazard scenarios, evaluating the potential consequence of the scenario, and identifying the safeguards or layers of protection necessary to drive risk to as low as reasonably practicable, LOPA becomes an effective organizational tool for implementing a Process Safety Management (PSM) mechanical integrity program.[49] LOPA also helps an organization decide which safeguards to focus on during operation, maintenance, and training.[i, 50] In addition, the LOPA methodology includes provisions allowing an organization to determine the availability[ii] and effectiveness of a safeguard or layer of protection in reducing the risk of a potential scenario.[51]

[i] Chevron is a member of CCPS and peer-reviewed the CCPS LOPA publication. *See* Center for Chemical Process Safety (CCPS). "Layer of Protection Analysis – Simplified Process Risk Assessment," page xiv, 2001.
[ii] The probability that a system will be able to perform its designated function when required for use. Another term frequently used is *Probability of Failure on Demand* (PFD). Availability = 1 - PFD. *See* Center for Chemical Process Safety (CCPS), "Guidelines for Safe Automation of Chemical Processes," page XIX, 1993.

Regulatory Oversight

65. The Contra Costa County Industrial Safety Ordinance (ISO) requires that regulated facilities[i] within the county implement safety programs to prevent chemical incidents. Since the ISO took effect in January 1999, Contra Costa County has continued to make improvements to the implementation of the prevention program's elements.

66. The purpose of the ISO is to "prevent accidental release of hazardous chemicals; improve accident prevention by soliciting participation from industry and the community; require industry to submit a Safety Plan; and conduct audits of the plan and inspections of the industrial plants."[52]

67. Although the City of Richmond is located in Contra Costa County, the county does not have jurisdiction over industrial facilities located within the city limits. Thus, the ISO is not enforceable within the City of Richmond. On December 18, 2001, the City of Richmond adopted its own industrial safety ordinance (RISO), based on the ISO.[ii, 53] The RISO covers the two facilities located within the City of Richmond: Chevron and General Chemical West Richmond Works.[54] Pursuant to an agreement between the two parties, Contra Costa County inspects these two facilities and implements the RISO for the City of Richmond.[55]

68. The ISO and RISO contain identical provisions that address the use of inherent safety concepts. Each defines "inherently safer systems" as "feasible alternative equipment, processes, materials, lay-outs and procedures meant to eliminate, minimize, or reduce the risk of a major chemical accident or release by modifying a process rather than adding external layers of protection."[56] Both regulations also require that:

> For all covered processes, the stationary source shall consider the use of inherently safer systems in the development and analysis of mitigation items resulting from a process hazard analysis and in the design and review of new processes and facilities. The stationary source shall select and implement inherently safer systems to the greatest extent feasible. If a stationary source concludes that an inherently safer system is not feasible, the basis for this conclusion shall be documented in meaningful detail.[57]

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[i] The ISO applies to oil refineries and chemical plants within the county jurisdiction that are required to submit a Risk Management Plan to EPA and are program level 3 stationary sources as defined by the California Accidental Release Prevention (CalARP) Program. There are seven facilities covered by the ISO, five of which are refineries. *See* http://cchealth.org/hazmat/iso/ (accessed April 17, 2013).

[ii] At the time of the August 6th incident, the RISO did not include amendments made to the ISO in 2006. The 2006 amendments required an expansion of human factors programs, expanded management of organizational change reviews, security vulnerability analyses, and safety culture assessments. These amendments were subsequently adopted by the City of Richmond in February 2013. *See* http://cchealth.org/hazmat/iso/ (accessed on April 9, 2013).

69. The apparent intent of the ISO and RISO regulations is to require companies to evaluate their processes in order to identify opportunities to implement inherently safer systems. However, the plain language contained within these regulations conflicts with this intent. Both regulations contain the following permissive language: "the stationary source *shall consider* the use of inherently safer systems…"[58] This language does not require companies to conduct a comprehensive analysis and implement inherently safer systems even where feasible. It only requires such an analysis be considered. The regulations allow companies to merely engage in an activity contemplating the potential use of inherently safer systems.

70. The language within the ISO and RISO regulations also requires effective action to implement inherently safer systems "to the greatest extent feasible."[59] If an inherently safer system is not implemented, the regulations require that the basis for this decision be "documented in meaningful detail."[60] However, these regulations do not require documentation supporting the adequacy of existing "inherently safer"[61] claims. Chevron's compliance with the RISO is indicative of this deficiency. In its inherently safer systems checklist, Chevron simply concluded that its systems were inherently safer to the extent that no modifications were necessary. However, the company offered no documentation to substantiate these claims. Had the ISO and RISO regulations required analysis of inherently safer systems regardless of what the site already had in place, Chevron may have implemented the inherently safer recommendations made by technical staff to replace the 4-sidecut with an inherently safer metallurgy.

71. The inherently safer systems requirements of the ISO and RISO are only triggered by the conduct of a PHA or the construction of a new process.[62] Rebuilds, repairs, MOCs, and the implementation of incident investigation corrective actions do not require the analysis and application of inherently safer systems.

72. The Contra Costa County PHA guidance document presents four categories of risk reduction:[i] inherent, passive, active, and procedural (Figure 15).[ii] It states that all four categories should be used in the development of recommendations from process hazard analyses.[63] It reiterates the CCPS statement that all may contribute to the overall safety of a process, but that inherent safety is the most effective.[64] It goes on to state "The inherent and passive categories should be implemented when feasible for new processes and facilities and used during the review of Inherently Safer Systems for existing processes if these processes could cause incidents that could result in a Major Chemical Accident or Release."[65] This wording in the guidance

[i] The guidance document uses CCPS definitions for the identified categories of risk reduction.
[ii] Inherent risk reduction involves eliminating the hazard by using materials and process conditions that are non-hazardous. Passive risk reduction is defined as minimizing the hazard through process and equipment design features that reduce the frequency or consequence of the hazard without active functioning of any device. Active risk reduction includes using controls, alarms, safety instrumented systems, and mitigation systems to detect and respond to process deviations from normal operation. Procedural risk reduction achieves the lowest level of risk reduction and involves using policies, operating procedures, training, administrative means, emergency response, and management approaches to prevent incidents and minimize the effects of an incident.

document demonstrates the importance Contra Costa County places on risk reduction and prevention such as metallurgy upgrades; however, as a guidance document, it is non-mandatory.

73. The California Division of Occupational Safety and Health (Cal/OSHA) has jurisdiction over employee safety in California.[66] Cal/OSHA is a division of the California Department of Industrial Relations and has operated a state plan industrial health and safety program since 1973 under a delegation from the U.S. Occupational Safety and Health Administration (OSHA). Cal/OSHA conducts inspections of California workplaces in response to industrial accidents, safety complaints, or as part of an inspection program targeting specific industries.[67] Consideration of inherently safer processes is not currently a required component of any Cal/OSHA (or federal OSHA) standard or regulation.[i]

74. The State of California has promulgated process safety regulations similar to OSHA[68] for the prevention or minimization of the consequences of the accidental release of acutely hazardous chemicals.[69] These regulations require that covered employers perform a PHA to identify, evaluate and control hazards involved in the process using recognized methodologies.[70]

75. California regulations, however, do not provide for a specific review of the effectiveness of the proposed safeguards to control the hazards identified in the PHA using recognized methodologies such as Layers of Protection Analysis (LOPA).[71] Additionally, California regulations do not have any requirements for the use of inherently safer systems analysis and the hierarchy of controls for establishing safeguards for identified process hazards. Cal/OSHA, like federal OSHA, also does not require damage mechanism hazard reviews as part of the PHA process.

76. The Energy Institute, an industry technical working group[ii] organized in the United Kingdom (UK), with contributions from regulators including the UK's Health and Safety Executive (HSE),[iii] as well as other entities,[iv] developed a document in 2008[v] that provides guidance on damage mechanism hazard reviews in the UK's offshore petrochemical industry. The guidance states that effective management of corrosion will contribute to equipment integrity and reduce risk from safety and environmental hazards.[72] In addition, during the design of a process, a corrosion review can be used to eliminate risks and achieve inherent safety.[73] The guidance also

[i] This is also the case for US EPA Risk Management Program and the California Accidental Release Prevention Program regulations.

[ii] The Energy Institute is the leading chartered professional membership body supporting individuals and organizations across the energy industry. With a combined membership of over 13,500 individuals and 300 companies in 100 countries, it provides an independent focal point for the energy community and a powerful voice to engage business and industry, government, academia and the public internationally. *See* http://www.energyinst.org/about-us (accessed April 17, 2013).

[iii] HSE is an independent regulator that is tasked with securing the health, safety and welfare of workers within the UK. *See* http://www.hse.gov.uk/aboutus/index.htm (accessed April 17, 2013).

[iv] Chevron Energy Technology Company (ETC) was one of roughly 30 entities recognized in the guidance document as providing contributions to the institute that were "key to the development of this publication…". *See* http://www.energyinstpubs.org.uk/pdfs/815.pdf (accessed April 17, 2013).

[v] *Ibid.*

notes that damage mechanism hazard reviews should provide a structured framework for identifying risks associated with corrosion and developing suitable risk reduction measures.[74] These reviews should cover failure mechanisms including, but not limited to corrosion, environmental cracking, erosion, and mechanical damage, such as vibration induced fatigue.[75] Finally, this guidance states that a formal, documented quantitative and logic based assessment should be used when conducting corrosion reviews.[76]

77. Under a rule issued by the U.S. Environmental Protection Agency (EPA),[77] a facility with a tank, drum, pipe, or other process[i] that contains an extremely hazardous toxic or flammable substance listed at 40 CFR §68.130 in an amount above the "threshold quantity" specified for that substance, is required to conduct a hazard assessment as well as develop a prevention program and an emergency response program. These requirements are documented in a Risk Management Plan (RMP) that is submitted to EPA. Covered facilities must implement the RMP and update their RMPs periodically or when certain changes occur. The goal of EPA's Risk Management Program is to prevent accidental releases of substances that can cause serious harm to the public and the environment from short-term exposures, and to mitigate the severity of releases that do occur.[78]

78. The EPA RMP program provisions build on the planning and preparedness groundwork laid by the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA). EPCRA establishes requirements for federal, state, and local governments, as well as industry, regarding emergency planning and "Community Right-to-Know" reporting on hazardous toxic chemicals. EPCRA "help[s] increase the public's knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment."[79] According to the U.S. EPA's Chemical Emergency Preparedness and Prevention Office,[ii] transparency between industry and the public will improve community safety:

> Both EPCRA and the CAA [Clean Air Act] section 112(r) Risk Management Program encourage communication between facilities and the surrounding communities about chemical safety and chemical risks. Regulatory requirements, by themselves, will not guarantee safety from chemical accidents. Information about hazards in a community will allow local emergency officials and the public to work with industry to prevent accidents.[80]

[i] "Process" means "any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities…" 40 CFR §68.3 (1997).

[ii] In 2004, the U.S. EPA's Chemical Emergency Preparedness and Prevention Office was merged with the Superfund Emergency Response Program and Oil Spill Prevention Program to form the Office of Emergency Management, or OEM. OEM works with other EPA partners, federal, state, and local agencies, and industry to prevent accidents and maintain and provide superb response capabilities. *See* http://www.epa.gov/oem/about.htm (accessed April 17, 2013).

> The CCPS also notes that governments and advocacy organizations have been successful in driving performance improvement by using public disclosure to make safety information available to the public.[81]

79. Under the RMP program's hazard assessment requirement, a facility must prepare a worst-case release scenario analysis[82] and complete a five-year accident history.[83] A covered facility must also develop and implement an emergency response program that includes procedures for informing the public and local agencies about accidental releases and procedures and measures for emergency response after an accidental release.[84] Officials and the public, including local emergency planning committees (LEPCs) can use this information to understand the chemical hazards in the community and then work with industry to address and mitigate those hazards. With both EPCRA and the Risk Management Program, the regulatory purpose and substantive provisions emphasize the importance of transparency, sharing of process safety data, and public participation to prevent chemical accidents. The CSB notes that post-incident, during the decision-making related to piping repairs to the crude unit, the public, worker representatives, regulators, and governmental bodies played a key role driving transparency, accountability, and improved risk reduction.

80. Workforce involvement is a key element of process safety and effective chemical accident prevention. In the Center for Chemical Process Safety publication, *Guidelines for Risk Based Process Safety*, it lists workforce involvement as one of 20 essential management systems necessary to reduce process safety risks and prevent chemical accidents.[85] CCPS states that:

> …workers are potentially the most knowledgeable people with respect to the day-to-day details of operating the process and maintaining the equipment and facilities and may be the sole source for some types of knowledge gained through their unique experiences. Workforce involvement provides management a mechanism for tapping into this valuable expertise.[86]

This CCPS publication discusses general areas of workforce involvement in risk assessments, inspections, audits, and performance reviews. The CCPS notes that participation leads to empowerment, management responsiveness, and process safety performance improvement.[87] The OSHA PSM Standard emphasizes the importance of participation by workers and their representatives. It requires employers to develop a written plan of action, consult with employees, and make available all process safety information.[88] In previous investigation reports, the CSB has identified that workers and their representatives play a very important role in major incident prevention. For example, in the BP Texas City oil refinery investigation report, the CSB recommended that BP and the United Steelworkers International Union (USW) establish a joint program to report incidents and near misses, and to ensure that recommendations made during investigations were implemented. The CSB also recommended

that API and the USW work together to develop a safety standard addressing leading and lagging process safety indicators.[i]

81. In July 2012, the CSB held a public hearing on process safety indicators[ii] to explore how companies and regulators use process safety metrics to manage risks and drive continuous safety improvements. During this hearing the CSB stated that, following the 2005 BP Texas City accident, both the CSB and Baker Panel[iii] reports noted the lack of focus by BP on process safety and inadequate performance measurement indicators. The CSB also noted that one goal of process safety indicators is to drive continuous process safety improvement, and that regulators can utilize these indicators to focus inspections, audits, and investigations.

82. Process safety management systems are critical for reducing process safety incidents. Process safety indicators are a significant element of these systems. Indicators measure the strengths and weaknesses of process safety management systems, to achieve and maintain safe and reliable operations.[89] Properly selected and managed indicators will identify the successes and point out the flaws of the system.[90]

83. In 2008, the CCPS published a guidance document for the development of leading[iv] and lagging[v] process safety indicators to assist industry in avoiding catastrophic chemical incidents.[91] While process safety indicators are an important tool for major accident prevention, the simple activity of identifying and recording process safety metrics will not drive process safety improvement. CCPS notes that these metrics must be "collected, analyzed, communicated, understood, and *acted upon.*"[92]

84. The UK HSE has published a guidance document to help chemical and major hazard industries develop process safety indicators. HSE states that:

> Most systems and procedures deteriorate over time, and system failures discovered following a major incident frequently surprise senior managers, who sincerely believed that the controls were functioning as designed. Used effectively, process

[i] Process safety indicators are also referred to as safety performance indicators, metrics, key process indicators (KPI), performance measures, indicators, etc…

[ii] *See* http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed April 17, 2013).

[iii] *See* http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/SP/STAGING/local_assets/assets/pdfs/Baker_panel_report.pdf (accessed April 12, 2013).

[iv] Leading indicators are measurements that predict future performance to ensure that safety protection layers and operating discipline are being maintained, including unsafe behaviors or insufficient operating discipline equipment selection, engineering design, specification of inspection frequency, and technique. *See* Center for Chemical Process Safety (CCPS), *Guidelines for Process Safety Metrics*, Page 20. 2010.

[v] Lagging indicators are facts about previous events, such as process safety incidents, that meet the threshold of severity and should be reported as part of the process safety metric. *See* Center for Chemical Process Safety (CCPS), "Guidelines for Process Safety Metrics," 2010; Page 20.

> safety indicators can provide an early warning, before catastrophic failure, that critical controls have deteriorated to an unacceptable level. [93]

85. The public can play an important role in monitoring safety management systems. In its recent guidelines, the CCPS promoted the sharing of process safety indicators with the public:

> Sharing performance metrics and results broadly can engage the public as a partner in holding the organization accountable for process safety performance. Making metrics and performance public can be an especially powerful way of maintaining upper management commitment since it will likely be the CEO or other senior managers who will be called to account by the public if goals are not met or performance declines. Communicating process safety successes also demonstrates to employees and the public that positive change can be, and are being, made within an organization. [94]

Recommendations

Under 42 U.S.C. 7412(r)(6)(C)(ii), the U.S. Chemical Safety and Hazard Investigation Board is charged with "recommending measures to reduce the likelihood or the consequences of incidental releases and proposing corrective steps to make chemical production, processing, handling and storage as safe and free from risk of injury as possible …." The CSB makes recommendations based on the findings and conclusions of the investigation. Recommendations are made to parties that can affect change to prevent future incidents, which may include the company, contractors, industry organizations responsible for developing good practice guidelines, regulatory bodies, and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations or professional societies.

Chevron U.S.A (Urgent)

2012-03-I-CA-R1

At all Chevron U.S. refineries, engage a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Analyze and incorporate into this review applicable industry best practices, Chevron Energy Technology Company findings and recommendations, and inherently safer systems to the greatest extent feasible.

2012-03-I-CA-R2

At all California Chevron U.S. refineries, report leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to the federal, state, and local regulatory agencies that have chemical release prevention authority.

Mayor and City Council,
City of Richmond, California

2012-03-I-CA-R3

Revise the Industrial Safety Ordinance (ISO) to require that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R4

Revise the Industrial Safety Ordinance (ISO) to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R5

Ensure the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1 and 2012-03-I-CA-R2), so that all necessary mechanical integrity work at the Chevron Richmond Refinery is identified and recommendations are completed in a timely way.

Board of Supervisors
Contra Costa County, California

2012-03-I-CA-R6

Revise the Industrial Safety Ordinance (ISO) to require that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R7

Revise the Industrial Safety Ordinance (ISO) to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R8

Monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1 and 2012-03-I-CA-R2), so that all necessary mechanical integrity work at the Chevron Richmond Refinery is identified and recommendations are completed in a timely way.

California State Legislature,
Governor of California

2012-03-I-CA-R9

Revise the California Code of Regulations, Title 8, Section 5189, Process Safety Management of Acutely Hazardous Materials, to require improvements to mechanical integrity and process hazard analysis programs for all California oil refineries. These improvements shall include engaging a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Require the analysis and incorporation of applicable industry best practices and inherently safety systems to the greatest extent feasible into this review.

2012-03-I-CA-R10

For all California oil refineries, identify and require the reporting of leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to state and local regulatory agencies that have chemical release prevention authority. These indicators shall be used to ensure that requirements described in 2012-03-I-CA-R9 are effective at improving mechanical integrity and process hazard analysis performance at all California oil refineries and preventing major chemical incidents.

2012-03-I-R11

Establish a multi-agency process safety regulatory program for all California oil refineries to improve the public accountability, transparency, and performance of chemical accident prevention and mechanical integrity programs. This program shall:

1. Establish a system to report to the regulator the recognized methodologies, findings, conclusions and corrective actions related to refinery mechanical integrity inspection and repair work arising from Process Hazard Analyses, California oil refinery turnarounds and maintenance-related shutdowns;
2. Require reporting of information such as damage mechanism hazard reviews, notice of upcoming maintenance-related shutdowns, records related to proposed and completed mechanical integrity work lists, and the technical rationale for any delay in work proposed but not yet completed;

3. Establish procedures for greater workforce and public participation including the public reporting of information; and
4. Provide mechanisms for federal, state and local agency operational coordination, sharing of data (including safety indicator data), and joint accident prevention activities. The California Department of Industrial Relations will be designated as the lead state agency for establishing a repository of joint investigative and inspection data, coordinating the sharing of data and joint accident prevention activities.

2012-03-I-CA-R12

Require that Process Hazard Analyses required under California Code of Regulations, Title 8, Section 5189 Section (e) include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R13

Require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new process, process unit rebuilds, significant process repairs and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R14

Monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R9 and 2012-03-I-CA-R10), so that all necessary mechanical integrity work at all California Chevron Refineries is identified and recommendations are completed in a timely way.

The U.S. Environmental Protection Agency

2012-03-I-CA-R15

Jointly plan and conduct inspections with Cal/OSHA, California EPA and other state and local regulatory agencies with chemical accident prevention responsibilities to monitor the effective implementation of the damage mechanism hazard review and disclosure requirements under 2012-03-I-CA-R9 and R10 above.

The Board of Supervisors, Contra Costa County, California, 2012-03-I-CA-R16;
The Mayor and City Council, City of Richmond, California, 2012-03-I-CA-R17;
The California Air Quality Management Divisions, 2012-03-I-CA-R18;
The U.S. Environmental Protection Agency, 2012-03-I-CA-R19; and
The California Environmental Protection Agency, 2012-03-I-CA-R20;

Participate in the joint regulatory program described in recommendation 2012-03-I-CA-R11. This participation shall include contributing relevant data to the repository of investigation and inspection data created by the California Department of Industrial Relations and jointly coordinating activities.

Additional Issues Currently Under Investigation

The following section highlights additional issues which the CSB has identified to date in its investigation of the Chevron Richmond Refinery fire and major hydrocarbon release that occurred on August 6, 2012. These issues relate to the ongoing CSB investigation of the management and regulation of health and safety at refineries. The CSB final report will make additional recommendations consistent with this interim report and will present additional detailed findings and analyses in a final report on the incident, to be released later in 2013.

Regulatory Oversight

The CSB noted in its BP Texas City (BPTC) Final Investigation Report (issued in March 2007) the importance of having a well-resourced, competent regulator consisting of individuals with the necessary training, education, and experience to conduct planned comprehensive and robust inspections of facilities with the goal of preventing catastrophic accidents. In a 1992 compliance directive[i] the federal Occupational Safety and Health Administration (OSHA) stated that the primary enforcement model for the Process Safety Management of Highly Hazardous Chemicals (PSM) standard would be planned, comprehensive, and resource-intensive Program Quality Verification (PQV) inspections to help prevent catastrophic accidents.[95] However, the CSB report noted that for the 10-year period prior to the Texas City incident, federal OSHA had conducted no planned PQV inspections in oil refineries. Regular planned inspections appropriately emphasize the prevention of accidents that are potentially catastrophic. Issuing fines and prosecuting companies post-incident are not acceptable substitutes for prevention. As a result, CSB recommended in its report that OSHA strengthen the planned enforcement of the OSHA Process Safety Management (PSM) standard by developing more highly trained and experienced inspectors to conduct more comprehensive inspections similar to those under OSHA's PQV program at facilities presenting the greatest risk of a catastrophic accident.

Spurred in part by the CSB's recommendations, OSHA issued the Petroleum Refinery Process Safety Management National Emphasis Program (NEP) on June 7, 2007.[ii] The NEP was a federal program that established guidelines for inspecting petroleum refineries to assure compliance with the PSM standard, 29 CFR §1910.119.[96] Unlike the PQV approach to inspections, which "employs a broad, open-ended inspection strategy and uses a more global approach to identify compliance deficiencies…,"[97] the NEP "provide[d] a specific tool to evaluate compliance with the [PSM] standard…[which] identifies a particular set of requirements from the PSM standard from which CSHOs [Compliance Safety and Health Officers] are to review documents, interview employees, and verify implementation for specific processes, equipment, and procedures."[98] While the CSB called for an ongoing comprehensive inspection

[i] Compliance directives are the main method OSHA uses to communicate plans, inspection methods, and compliance expectations to their Compliance Safety and Health Officers (CSHOs) for enforcing a new regulation.
[ii] Originally Directive Number CPL 03-00-004. Extended August 18, 2099 as Directive Number CPL 03-00-010 to allow more time to complete NEP inspections under the original CPL 03-00-004.

program, inspections being conducted pursuant to the NEP were terminated in 2011. The CSB recommendation to OSHA remains Open.[i]

OSHA State Plan States[ii] were strongly encouraged but not required to implement the NEP. California's Division of Occupational Safety and Health (Cal/OSHA) did not adopt the NEP "because of its dedicated PSM Unit."[99] Cal/OSHA informed the CSB that federal OSHA approved this decision in 2007. In lieu of conducting NEP inspections, Cal/OSHA's PSM Unit has conducted and continues to conduct a full range of programmed, accident, complaint, and referral inspections of PSM-covered facilities in the state of California pursuant to the California Labor Code, Title 8 regulations, and Cal/OSHA's Policy and Procedures (P&P) Manual C-17 "Process Safety Management,"[iii] to ensure these facilities are complying with PSM requirements.

Between 2006 and August 6, 2012, Cal/OSHA conducted three planned inspections of the Chevron Richmond facility, totaling only 150 inspector hours of effort. None of these inspections resulted in citations or fines. In contrast, according to statistics provided by OSHA, federal NEP refinery inspections conducted between 2007 and the end of 2011 lasted roughly 1,000 inspector hours each and resulted in an average of 11.2 violations and $76,821 in penalties per inspection. OSHA noted that hours spent on a typical federal refinery NEP inspection were 40 times greater than the average OSHA inspection. These numbers indicate a major disparity in thoroughness and comprehensiveness between the planned inspections conducted by Cal/OSHA and the NEP inspections conducted by OSHA and other OSHA State Plan States.

The safety case is a rigorous prescriptive and goal-setting regulatory regime that is highlighted by its adaptability and requirements for continuous improvements in risk reduction for high hazard industrial facilities. The approach is used widely overseas but is not used currently for U.S. process industries. The CSB is currently examining whether the implementation of the safety case regime could be a more effective regulatory tool for Cal/OSHA in its effort to ensure that California refineries are identifying and controlling hazards and ultimately driving risk to as low as reasonably practicable (ALARP). Utilizing the safety case requires effective implementation by an independent, competent, well-funded regulator. Experience and competence of the regulator in technical areas such as chemical engineering, human factors, and process safety are necessary to provide effective auditing and regulatory oversight for prevention. To ensure effective implementation of the safety case, industry standards and guidelines must be rigorous and up-to-date as well. The CSB notes that relevant and applicable industry standards and guidelines – such as API RP 939-C – currently contain voluntary and permissive language. The CSB will be examining the need for more effective good practice standards and guidelines containing the necessary requirements to prevent catastrophic accidents.

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[i] Open - Awaiting Response or Evaluation/Approval of Response (O - ARE/AR) - The recipient has not submitted a substantive response, or the evaluation by CSB staff of a response is pending, or the Board has not yet acted on staff recommendation of status.

[ii] Section 18 of the Occupational Safety and Health Act of 1970 encourages States to develop and operate their own job safety and health programs, referred to informally as an OSHA State Plan. OSHA approves and monitors State plans and provides up to 50 percent of an approved plan's operating costs.

[iii] Issued June 6, 1994. Revised August 1, 1994 and May 19, 2007.

In addition to the issues discussed above, the CSB will also be examining the need for the reporting of leading and lagging process safety indicators to the regulator; the regulator's effective use of these process safety indicators; workforce and stakeholder involvement in regulatory oversight of refineries; and the thoroughness of Contra Costa County's safety auditing of the Chevron facility.

Emergency Planning and Reporting

According to information provided by Contra Costa Emergency Medical Services, 15,213 individuals sought emergency medical attention between August 6 and August 23, 2012, due to the Chevron refinery major hydrocarbon release and fire.

CSB Investigation Team members visited local hospitals the week of the incident to better understand the impact on the surrounding community. Officials at Doctor's Medical Center (DMC) in San Pablo, California, informed the CSB that in the days following the incident they were inundated with emergency room visits and found it difficult to handle the influx due to a lack of funding and staffing. Officials at both DMC and Kaiser Permanente Hospital (KP) in Richmond told the CSB that they lacked specific knowledge of the chemicals released as a result of the incident, complicating efforts to evaluate and treat individuals.

The California Code of Regulations (CCR) requires that owners and operators of hazardous waste facilities make "arrangements to familiarize local hospitals with the properties of hazardous waste handled at the facility and the types of injuries or illnesses which could results from fires, explosions, or releases at the facility."[100] The CSB is currently evaluating ways to ensure that hospitals have the information necessary to properly evaluate and treat individuals that may be exposed to releases from facilities in Contra Costa County.

Following the incident, Contra Costa County's Community Warning System (CWS) notified the surrounding community of a hazardous material incident and ordered a shelter-in-place (SIP). The CWS uses sirens, the news media, and phone calls to residents in order to initiate the SIP. Contra Costa County issued the SIP on August 6, 2012, at 6:38 pm for the cities of Richmond, San Pablo, and North Richmond, California, and lifted the SIP later that evening at 11:12 pm. However, the CSB has learned that some phone calls notifying residents of the SIP did not occur until over four hours after the release.

It is essential that responders, community residents, and hospitals in the areas surrounding industrial facilities be aware of what hazardous materials exist at these facilities, what specific chemicals are released into the community in the event of an incident, and what is known about the potential acute and chronic health impacts. The CSB will be analyzing ways to strengthen current regulations and policies to ensure there is proper emergency planning and reporting for industrial facilities in Contra Costa County and the state of California.

Emergency Response

OSHA provides guidance on emergency response in its *Hazardous Waste Operations and Emergency Response* standard, known as HAZWOPER, under 29 CFR §1910.120 (p) and (q). Under 29 CFR §1910.120(q)(6), the HAZWOPER standard contains requirements for training and qualification of all individuals involved in emergency response related to their roles and responsibilities.

Good safety practice dictates that individuals responding to emergencies should have the technical knowledge to give input into shutdown decisions, set up an incident command structure, establish boundary limits, and evaluate the "hot zone." Access to the hot zone must be strictly limited to personnel with higher degrees of specific training, experience, and appropriate personal protective equipment; all others must be removed to a safe location away from chemical hazards. Hot zone boundaries must be established to anticipate the possible escalation of releases and the positioning of firefighting equipment such as fire trucks.

The CSB will be looking at the sufficiency of regulatory requirements, industry standards, and good practices, in addition to evaluating emergency response decision-making following the leak and subsequent pipe rupture (including the training and qualification of responders) to determine whether improvements are needed in these areas.

Safety Culture

The Center for Chemical Process Safety (CCPS) defines process safety culture as the "combination of group values and behaviors that determines the manner in which process safety is managed."[101] As the CSB noted in its BP Texas City Report, safety culture can be influenced by management changes, historical events, and economic pressures. After reviewing evidence and decisions made relating to materials of construction and mechanical integrity within the crude unit at the Chevron refinery, as well as the response to the leak on August 6, 2012, the CSB has determined that issues relating to safety culture are relevant to this incident. The CSB will examine the Chevron Richmond Refinery's approach to safety, its safety culture and any organizational deficiencies, to determine how to best prevent future incidents.

The CSB notes that on August 6, 2012, following discovery of the leak on the 4-sidecut piping, Chevron hoped to forestall a shutdown by installing a leak repair clamp.[i] Chevron's mechanical integrity management system has not been fully successful in detecting and replacing deteriorated piping components prior to failure, resulting in the company's frequent use of leak repair clamps[ii] to externally stop process fluid leaks. Chevron's reliance on such clamps to mitigate process piping component leaks identifies serious questions about its mechanical integrity program. The CSB determined that Chevron

[i] Chevron's leak repair clamp vendor was called out to the scene of the leak to help determine potential clamping options.

[ii] Leak repair clamps are mechanical devices designed and installed to stop a leak from a piping component such as piping, valves, flanges, and instrumentation. These devices are typically intended to provide a temporary repair while a process continues operation until a plant shutdown takes place and a permanent repair can be made.

has more than 100 clamps on hydrocarbon and other process piping components at the Richmond refinery. The leak repair clamp is typically relied upon to prevent further leaking until the next unit turnaround, when the deteriorated piping component can be repaired. However, Cal/OSHA citations following the August 6, 2012, fire in the crude unit identified that Chevron has not always replaced these clamps during unit turnarounds and these devices then remain in service significantly longer than originally intended. The CSB determined that Chevron has leak repair clamps in place on piping components containing hazardous flammable process fluids including applications where the process material is above the autoignition temperature. Some of these leak repair clamp applications are in locations where a permanent repair would not have required a unit shutdown. The CSB will further evaluate the frequent use of leak repair clamps by Chevron and the potential that the deviance of a weak mechanical integrity management system has been normalized.[i]

[i] Normalization of deviance is a long-term phenomenon in which individuals or work teams gradually accept a lower standard of performance until the lower standard becomes the norm. It is typically the result of conditions slowly changing and eroding over time. *See* Center for Chemical Process Safety (CCPS), Recognizing Catastrophic Incident Warning Signs in the Process Industries, Page 4. 2012.

BY THE

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Date of Approval April __, 2013.

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