

APPENDIX B

EMISSIONS CALCULATIONS

Recovery Technology Solutions, LLC
SIP Permit Application
December 2012

TABLE B.1 - FACILITY WIDE EMISSIONS SUMMARY

POTENTIAL TO EMIT (PTE):

Pollutant	PTE (tpy)						
	GP01 ¹	DR01 ²	SC01	B001	H001	FP01	TOTAL
PM	-	91.3	0.1	0.2	0.0	0.0	91.6
PM ₁₀	-	91.3	0.0	0.7	0.1	0.0	92.1
PM _{2.5}	-	91.3	0.0	0.7	0.1	0.0	92.1
NO _x	-	-	-	12.5	2.5	0.8	15.8
SO ₂	-	-	-	0.1	0.0	0.3	0.3
CO	-	-	-	7.2	1.4	0.8	9.5
VOC	286.2	-	-	0.8	0.2	0.3	287.4
CO ₂ e	-	-	-	11,969.3	2,402.6	144.2	14,516.1
Toluene (highest single HAP)	286.2	-	-	0.0	0.0	0.0	286.2
Total HAPs	286.2	-	-	0.2	0.0	0.0	286.4

PREDICTED ACTUAL EMISSIONS:

Pollutant	Predicted Actual Emissions (tpy)						
	GP01 ¹	DR01 ²	SC01	B001	H001	FP01	TOTAL
PM	-	3.2	0.1	0.2	0.0	0.0	3.6
PM ₁₀	-	6.5	0.0	0.7	0.1	0.0	7.3
PM _{2.5}	-	6.5	0.0	0.7	0.1	0.0	7.3
NO _x	-	-	-	12.5	2.5	0.8	15.8
SO ₂	-	-	-	0.1	0.0	0.3	0.3
CO	-	-	-	7.2	1.4	0.8	9.5
VOC	74.3	-	-	0.8	0.2	0.3	75.5
CO ₂ e	-	-	-	11,969.3	2,402.6	144.2	14,516.1
Toluene (highest single HAP)	74.3	-	-	0.0	0.0	0.0	74.3
Total HAPs	74.3	-	-	0.2	0.0	0.0	74.5

1. GP001 Toluene PTE is conservative based on the proposed Case-by-Case MACT limit of 0.9 gallon solvent loss per ton of shingle processed (see Appendix D)

GP001 Toluene Predicted Actual Emissions account for air emissions only (i.e.: steady state air emissions, fugitives, and equipment cleaning)

The amount of toluene lost in products (asphalt oil, solids, and water) are not included in the Predicted Actual Emissions because they are not emitted to the air. Additionally, other system losses (i.e.: due to malfunction, offspec material, etc) are also not included in the Predicted Actual Emissions because they are already accounted for in the Steady-State Emissions.

2. DR01 PM PTE are pre-control emissions (conservative). DR01 is equipped with a cyclone.

DR01 PM Predicted Actual Emissions take into account cyclone efficiency

SUMMARY PTE vs. PREDICTED ACTUAL EMISSIONS

Pollutant	PTE (tpy)	Predicted Actual Emissions (tpy)	HAP Major Source Threshold (tpy)	PSD Major Source Threshold (tpy)
PM	91.6	3.6	---	250
PM ₁₀	92.1	7.3	---	250
PM _{2.5}	92.1	7.3	---	250
NO _x	15.8	15.8	---	250
SO ₂	0.3	0.3	---	250
CO	9.5	9.5	---	250
VOC	287.4	75.5	---	250
CO ₂ e	14,516.1	14,516.1	---	100,000
Toluene (highest single HAP)	286.2	74.3	10	---
Total HAPs	286.4	74.5	25	---

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TABLE B.2 - SOLVENT LOSS CALCULATIONS (SOURCE CODE GP01)

Solvent loss calculations are provided as vendor guarantee to RTS by the extraction and separation equipment vendor

See Appendix E for detail emissions calculations document

Solvent Losses Per (Vendor Guarantee) =	0.864 gal toluene per ton roofing material
Maximum Production Rate =	250 ton/day
Annual Solvent Losses (Per Vendor Guarantee) =	572,378 lb/yr
	286 ton/yr

For conservative assumption, assume all solvent losses are emitted to the air (PTE)

Therefore,

Toluene PTE = 286 ton/yr

Predicted Actual Air Emissions of Toluene are conservatively estimated follows*

Toluene Predicted Actual Emissions = (Steady State Losses to Air) + (Steady State Fugitive Losses) + (Process Equipment Cleaning Losses)

Toluene Predicted Actual Emissions = (3.44 x 8760) + (8.99 x 8760) + (39694)

Toluene Predicted Actual Emissions = 148,565 lb/yr

Toluene Predicted Actual Emissions = 74 tpy

*Notes:

Other System Losses (process halts, stoppages, shutdowns, off-spec materials) are already accounted for in the Steady State Losses to Air

Additionally, no credit for recovered solvent (from the process condensers and MOS)

Therefore, the projected actual air emissions are considered a conservative estimate

Breakdown of Solvent Losses (Vendor Guarantee):

A. Steady State Operation Losses	Lb/Hr	
1. Air	3.44	<-- air emissions
2. Water	0.076	
3. Solids	6.25	
4. Asphalt	5.21	
5. Fugitives	8.99	<-- air emissions
Total	23.97	

B. Other System Losses	Lb/Yr	
1. Process Halts	11,709	
2. Stoppages	33,654	
3.a. Full Purge Shutdowns	35,730	
3.b. Partial Purge Shutdowns	71,369	
3.c. Non-Purge Shutdowns	41,818	
4. Off-Spec Raw Materials	13,984	
5. Process Equipment Cleaning	39,694	<-- air emissions
Total	247,957	

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TABLE B.3 - DRYER (SOURCE CODE DR01) EMISSIONS CALCULATIONS

Emission Unit:	DR01	Dryer
APCD	CYC1	Cyclone
Maximum Dryer Throughput:	250	tons per day (tpd)
Average Hourly Throughput:	10	tons per hour (tph)
Annual Throughput:	91,250	tons per year (tpy)
Hours of Operation:	8,760	hours per year

Pollutant	Emission Factor ¹ (lb/ton)	Emission Rate (lbs/hr)	Maximum Uncontrolled Emissions (tons/yr)	Pollution Control Efficiency (%)	Controlled Emission Rate (lbs/hr) ²	Maximum Controlled Emissions (tons/yr)
PM - Filterable	2.00	20.83	91.25	84.5%	3.23	14.16
PM ₁₀ - Filterable	2.00	20.83	91.25	69.0%	6.47	28.32
PM _{2.5} - Filterable	2.00	20.83	91.25	69.0%	6.47	28.32

¹ Uncontrolled emission factors for PM were conservatively assumed to be equal to those of a sand and gravel dryer (SCC 3-05-027-20). Emission factors from AP-42 section 11.19.1 Table 11.19.1-1 for Industrial Sand and Gravel Processing. PM was assumed to equal PM₁₀ and PM_{2.5}.

² Dryer emissions will be controlled by a cyclone. Pollution control efficiency was estimated using grain loading limits provided by the cyclone vendor. The limits for PM and PM₁₀ were given as 0.020 and 0.040 gr/dscf respectively, and PM_{2.5} was assumed equal to PM₁₀.

Pollutant	Efficiency of the cyclone (gr/dscf)	Airflow (acfm)	Airflow (dcfm)	Controlled Emission Rate (lb/hr)
PM - Filterable	0.020	20,000	18,857	3.23
PM ₁₀ - Filterable	0.040	20,000	18,857	6.47
PM _{2.5} - Filterable	0.040	20,000	18,857	6.47

Conversion = 7,000 gr/lb PM/PM₁₀

Air Flow =	acfm	F	scfm	dscfm
	20,000	100	18,857	18,857

Worst case assume dscfm = scfm

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TABLE B.4 - SCREENING EQUIPMENT (SOURCE CODE SC01) EMISSIONS CALCULATIONS

Emission Unit:	SC01	Screening Process (equipped with fabric filter)
Control Equipment:	NA	
Screen Throughput:	188	tons per day (tpd) <i>(Based on 75% solid material in the shingles processed)</i>
Average Hourly Throughput:	8	tons per hour (tph)
Annual Throughput:	68,438	tons per year (tpy)
Hours of Operation:	8,760	hours per year

Pollutant	Emission Factor ¹ (lb/ton)	Emission Rate (lbs/hr)	PTE (tpy)
PM - Filterable	0.0022	0.02	0.08
PM ₁₀ - Filterable	0.00074	0.01	0.03
PM _{2.5} - Filterable	0.00005	0.00	0.00

¹ Emission factors for PM were obtained from AP-42, Section 11.19.2 for Crushed Stone Processing and Pulverized Mineral Processing, Table 11.19.2-2 for Screening (Controlled). The product sent through the screener will consist of sand and aggregate, limestone or fly ash, felt or fiberglass, and deleterious building material.

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TABLE B.5.a - BOILER (SOURCE CODE B001) EMISSIONS CALCULATIONS - CRITERIA POLLUTANTS

Emission Unit:	B001	Boiler 1
Control Equipment:	NA	
Maximum Rated Boiler Capacity :	600.0	Hp
	20.1	MMBtu/hr ¹
Maximum Design Capacity :	20,700	lbs/hr steam ¹

¹ American Society of Mechanical Engineers:

BHp = 29.87 MMBtu/hr
 BHp = 34.5 lbs/hr steam

Fuel Type	% Sulfur	% Ash	Heat Value	Units	Maximum Fuel Consumption Rate	Units	Maximum Fuel Consumption Rate	Units
Natural Gas	0.2	Negligible	1,020	Btu/scf	19,693	cf/hr	172.5	MMscf/yr
Propane	0.18	Negligible	91.5	MMBtu/10 ³ gal	219.5	gal/hr	1,923	10 ³ gal/yr

Natural gas: Heat value AP-42 Section 1.4 Table 1.4-1 (July 1998)

Sulfur AP-42 Section 1.4 Table 1.4-2 (July 1998)

Propane: Heat value AP-42 Section 1.5 Table 1.5-1 (July 2008)

Sulfur AP-42 Section 1.5 Table 1.5-1 (July 2008)

Calculations - Primary Fuel : Natural Gas							
Pollutant	Emission Factor ¹ (lb/10 ⁶ scf)	Emission Factor (lb/MMBtu)	Uncontrolled Emission Rate (lbs/hr)	Maximum Uncontrolled Emissions (tons/yr)	Pollution Control Efficiency (%)	Controlled Emission Rate (lbs/hr)	Maximum Controlled Emissions (tons/yr)
PM - Filterable ²	1.90	1.9E-03	0.04	0.16	0.0%	0.04	0.16
PM ₁₀ - Total	7.60	7.5E-03	0.15	0.66	0.0%	0.15	0.66
PM _{2.5} - Total	7.60	7.5E-03	0.15	0.66	0.0%	0.15	0.66
NO _x	100	9.8E-02	1.97	8.63	0.0%	1.97	8.63
SO ₂	0.60	5.9E-04	0.01	0.05	0.0%	0.01	0.05
CO	84	8.2E-02	1.65	7.25	0.0%	1.65	7.25
VOC	5.50	5.4E-03	0.11	0.47	0.0%	0.11	0.47
Lead	5.00E-04	4.9E-07	0.00	4.3E-05	0.0%	9.8E-06	4.3E-05

¹ Emission factors from AP-42 Section 1.4 "Natural Gas Combustion", Tables 1.4-1 and 2 (July 1998). PM_{2.5} is conservatively assumed to equal PM₁₀.

2. Note that PM only includes filterable PM per EPA FR Notice "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5}): Amendment to the Definition of "Regulated NSR Pollutant" Concerning Condensable Particulate Matter" dated 10/25/2012 (<http://www.gpo.gov/fdsys/pkg/FR-2012-10-25/pdf/2012-25978.pdf>)

Calculations - Backup Fuel : Propane							
Pollutant	Emission Factor ¹ (lb/10 ³ gal)	Emission Factor (lb/MMBtu)	Uncontrolled Emission Rate (lbs/hr)	Maximum Uncontrolled Emissions (tons/yr)	Pollution Control Efficiency (%)	Controlled Emission Rate (lbs/hr)	Maximum Controlled Emissions (tons/yr)
PM - Filterable ²	0.2	2.19E-03	0.04	0.19	0.0%	0.04	0.19
PM ₁₀ - Total	0.7	7.65E-03	0.15	0.67	0.0%	0.15	0.67
PM _{2.5} - Total	0.7	7.65E-03	0.15	0.67	0.0%	0.15	0.67
NO _x	13	1.42E-01	2.85	12.50	0.0%	2.85	12.50
SO ₂	0.018	1.97E-04	0.00	0.02	0.0%	0.00	0.02
CO	7.5	8.20E-02	1.65	7.21	0.0%	1.65	7.21
VOC	0.8	8.74E-03	0.18	0.77	0.0%	0.18	0.77
Lead	---	---	---	---	---	---	---

¹ Emission factors from AP-42 Section 1.5 Table 1.5-1 (July 2008) Industrial Boilers. PM_{2.5} is conservatively assumed to equal PM₁₀.

SO₂ EF = 0.1 * Sulfur (gr/100ft³)

VOC EF = TOC EF - CH₄ EF = 1.0 - 0.2 = 0.8

2. Note that PM only includes filterable PM per EPA FR Notice "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5}): Amendment to the Definition of "Regulated NSR Pollutant" Concerning Condensable Particulate Matter" dated 10/25/2012 (<http://www.gpo.gov/fdsys/pkg/FR-2012-10-25/pdf/2012-25978.pdf>)

Worse-Case Potential-to-Emit Summary:				
Pollutant	Uncontrolled Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (ton/yr)	Maximum Controlled Emissions (ton/yr)	Worst Case Fuel
PM	0.04	0.2	0.2	Propane
PM ₁₀	0.15	0.7	0.7	Propane
PM _{2.5}	0.15	0.7	0.7	Propane
NO _x	2.85	12.5	12.5	Propane
SO ₂	0.01	0.1	0.1	Natural Gas
CO	1.65	7.2	7.2	Natural Gas
VOC	0.18	0.8	0.8	Propane
Lead	9.85E-06	4.31E-05	4.31E-05	Natural Gas

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TABLE B.5.b - BOILER (SOURCE CODE B001) EMISSIONS CALCULATIONS - HAPs

Emission Unit:	B001	Boiler 1
Control Equipment:	NA	
Maximum Rated Boiler Capacity:	20.1	MMBtu/hr

Fuel Type	% Sulfur	% Ash	Heat Value	Units	Maximum Fuel Consumption Rate	Units
Natural Gas	0.2	Negligible	1,020	Btu/scf	172.5	10 ⁶ scf/yr
Propane	0.18	Negligible	91.5	MMBtu/10 ³ gal	1,923	10 ³ gal/yr

Natural gas: Heat value AP-42 Section 1.4 Table 1.4-1 (July 1998)
Propane: Heat value AP-42 Section 1.5 Table 1.5-1 (July 2008)

Sulfur AP-42 Section 1.4 Table 1.4-2 (July 1998)
Sulfur AP-42 Section 1.5 Table 1.5-1 (July 2008)

Note: There are no HAP emission factors available in AP-42 Section 1.5 for Propane (backup fuel).

Calculations Summary - Primary Fuel : Natural Gas						
	Uncontrolled	Uncontrolled	Maximum	Pollution	Controlled	Maximum
	Emission	Emission	Uncontrolled	Control	Emission	Controlled
HAP Name	Factor ¹	Rate	Emissions	Efficiency	Factor	Emissions
[CAS]	(lbs/10 ⁶ scf)	(lbs/hr)	(tons/yr)	(%)	(lbs/10 ⁶ scf)	(tons/yr)
Arsenic [7440-38-2]	2.00E-04	3.94E-06	1.73E-05	0.00%	NA	1.73E-05
Benzene [71-43-2]	2.10E-03	4.14E-05	1.81E-04	0.00%	NA	1.81E-04
Beryllium [7440-41-7]	1.20E-05	2.36E-07	1.04E-06	0.00%	NA	1.04E-06
Cadmium [7440-43-9]	1.10E-03	2.17E-05	9.49E-05	0.00%	NA	9.49E-05
Chromium [7440-47-3]	1.40E-03	2.76E-05	1.21E-04	0.00%	NA	1.21E-04
Cobalt [7440-48-4]	8.40E-05	1.65E-06	7.25E-06	0.00%	NA	7.25E-06
Dichlorobenzene [25321-22-6]	1.20E-03	2.36E-05	1.04E-04	0.00%	NA	1.04E-04
Formaldehyde [50-00-0]	7.50E-02	1.48E-03	6.47E-03	0.00%	NA	6.47E-03
Hexane [110-54-3]	1.80E+00	3.54E-02	1.55E-01	0.00%	NA	1.55E-01
Manganese [7439-96-5]	3.80E-04	7.48E-06	3.28E-05	0.00%	NA	3.28E-05
Mercury [7439-97-6]	2.60E-04	5.12E-06	2.24E-05	0.00%	NA	2.24E-05
Naphthalene [91-20-3]	6.10E-04	1.20E-05	5.26E-05	0.00%	NA	5.26E-05
Nickel [7440-02-0]	2.10E-03	4.14E-05	1.81E-04	0.00%	NA	1.81E-04
POM ²	6.98E-04	1.37E-05	6.02E-05	0.00%	NA	6.02E-05
Selenium [7782-49-2]	2.40E-05	4.73E-07	2.07E-06	0.00%	NA	2.07E-06
Toluene [108-88-3]	3.40E-03	6.70E-05	2.93E-04	0.00%	NA	2.93E-04
Totals		3.72E-02	1.63E-01			1.63E-01

¹ Emission factors from AP-42 Section 1.4 (07/98)

² Total POM emission factor is equal to the sum of the individual POM compounds and includes Naphthalene. Naphthalene is not double counted in the total HAP

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TABLE B.5.c - BOILER (SOURCE CODE B001) EMISSIONS CALCULATIONS - GHGs

Emission Unit:	B001	Boiler 1
Control Equipment:	NA	
Maximum Rated Boiler Capacity:	20.1	MMBtu/hr

Note - GHG Emission Factors from 40 CFR Part 98 Subpart C (GHG Mandatory Reporting Rule, Combustion)
GWP Conversion factors from Table A-1 to Subpart A of Part 98—Global Warming Potentials.

Primary Fuel:		Natural Gas			
GHG Pollutant	GWP	Emission Factor	PTE		
		(lb/MMBtu)	(lb/hr)	(tpy)	CO ₂ e (tpy)
CO ₂	1	116.89	2,348	10,284	10,284
CH ₄	21	2.20E-03	0.04	0.19	4.1
N ₂ O	310	2.20E-04	0.00	0.02	6.0
Total GHG (CO ₂ e)					10,294

Primary Fuel:		Propane			
GHG Pollutant	GWP	Emission Factor	PTE		
		(lb/MMBtu)	(lb/hr)	(tpy)	CO ₂ e (tpy)
CO ₂	1	135.49	2,722	11,921	11,921
CH ₄	21	6.61E-03	0.13	0.58	12.2
N ₂ O	310	1.32E-03	0.03	0.12	36.1
Total GHG (CO ₂ e)					11,969

Worst-Case Potential-to-Emit Summary			
GHG Pollutant	PTE		
	(lb/hr)	(tpy)	CO ₂ e (tpy)
CO ₂	2,722	11,921	11,921
CH ₄	0.13	0.58	12.22
N ₂ O	0.03	0.12	36.08
Total GHG (CO ₂ e)			11,969

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TABLE B.6.a - PROCESS HEATER (SOURCE CODE H001) EMISSIONS CALCULATIONS - CRITERIA POLLUTANTS

Emission Unit: H001 Process Heater for Oil
Control Equipment: NA
Maximum Rated Boiler Capacity: 120.4 Hp
4.0 MMBtu/hr
Maximum Design Capacity : 4,155 lbs/hr steam ¹

¹ American Society of Mechanical Engineers: BHp = 29.87 MMBtu/hr
BHp = 34.5 lbs/hr steam

Fuel Type	% Sulfur (gr/100scf)	% Ash	Heat Value	Units	Maximum Fuel Consumption Rate	Units	Maximum Fuel Consumption Rate	Units
Natural Gas	0.2	Negligible	1,020	Btu/scf	3,953	cf/hr	34.6	MMscf/yr
Propane	0.18	Negligible	91.5	MMBtu/10 ³ gal	44.1	gal/hr	386	10 ³ gal/yr

Natural gas: Heat value AP-42 Section 1.4 Table 1.4-1 (July 1998)
Propane: Heat value AP-42 Section 1.5 Table 1.5-1 (July 2008)

Sulfur AP-42 Section 1.4 Table 1.4-2 (July 1998)
Sulfur AP-42 Section 1.5 Table 1.5-1 (July 2008)

Calculations - Primary Fuel : Natural Gas							
Pollutant	Emission Factor ¹ (lb/10 ⁶ scf)	Emission Factor (lb/MMBtu)	Uncontrolled Emission Rate (lbs/hr)	Maximum Uncontrolled Emissions (tons/yr)	Pollution Control Efficiency (%)	Controlled Emission Rate (lbs/hr)	Maximum Controlled Emissions (tons/yr)
PM - Filterable ²	1.90	1.9E-03	0.008	0.03	0.0%	0.008	0.03
PM ₁₀ - Total	7.60	7.5E-03	0.030	0.13	0.0%	0.030	0.13
PM _{2.5} - Total	7.60	7.5E-03	0.030	0.13	0.0%	0.030	0.13
NO _x	---	1.3E-01	0.53	2.3	0.0%	0.53	2.3
SO ₂	0.60	5.9E-04	2.4E-03	1.0E-02	0.0%	2.4E-03	1.0E-02
CO	---	3.7E-02	0.15	0.7	0.0%	0.15	0.7
VOC	5.50	5.4E-03	0.022	0.10	0.0%	0.022	0.10
Lead	0.0005	4.9E-07	2.0E-06	8.7E-06	0.0%	2.0E-06	8.7E-06

¹ Emission factors from AP-42 Section 1.4 "Natural Gas Combustion", Tables 1.4-1 and 2 (July 1998). PM_{2.5} is conservatively assumed to equal PM₁₀.

2. Note that PM only includes filterable PM per EPA FR Notice "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5}): Amendment to the Definition of "Regulated NSR Pollutant" Concerning Condensable Particulate Matter" dated 10/25/2012 (<http://www.gpo.gov/fdsys/pkg/FR-2012-10-25/pdf/2012-25978.pdf>).

Calculations - Backup Fuel : Propane							
Pollutant	Uncontrolled Emission Factor (lb/10 ³ gal) ¹	Emission Factor (lb/MMBtu)	Uncontrolled Emission Rate (lbs/hr)	Maximum Uncontrolled Emissions (tons/yr)	Pollution Control Efficiency (%)	Controlled Emission Rate (lbs/hr)	Maximum Controlled Emissions (tons/yr)
PM - Filterable ²	0.2	0.0022	0.01	0.0	0.0%	0.01	0.0
PM ₁₀ - Total	0.7	0.0077	0.03	0.1	0.0%	0.03	0.1
PM _{2.5} - Total	0.7	0.0077	0.03	0.1	0.0%	0.03	0.1
NO _x	13	0.1421	0.57	2.5	0.0%	0.57	2.5
SO ₂	0.018	1.97E-04	7.93E-04	3.5E-03	0.0%	7.93E-04	3.47E-03
CO	7.5	0.0820	0.33	1.4	0.0%	0.33	1.4
VOC	0.8	0.0087	0.04	0.15	0.0%	0.04	0.2
Lead	---	---	---	---	---	---	---

¹ Emission factors from AP-42 Section 1.5 Table 1.5-1 (July 2008) Industrial Boilers. PM_{2.5} is conservatively assumed to equal PM₁₀.

SO₂ EF = 0.1 * Sulfur (gr/100ft³)

VOC EF = TOC EF - CH₄ EF = 1.0 - 0.2 = 0.8

2. Note that PM only includes filterable PM per EPA FR Notice "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM_{2.5}): Amendment to the Definition of "Regulated NSR Pollutant" Concerning Condensable Particulate Matter" dated 10/25/2012 (<http://www.gpo.gov/fdsys/pkg/FR-2012-10-25/pdf/2012-25978.pdf>).

Worse-Case Potential-to-Emit Summary:				
Pollutant	Uncontrolled Emission Rate (lb/hr)	Maximum Uncontrolled Emissions (ton/yr)	Maximum Controlled Emissions (ton/yr)	Worst Case Fuel
PM - Filterable ²	0.01	0.04	0.04	Propane
PM ₁₀ - Total	0.03	0.14	0.14	Propane
PM _{2.5} - Total	0.03	0.14	0.14	Propane
NO _x	0.57	2.51	2.51	Propane
SO ₂	0.00	0.01	0.01	Natural Gas
CO	0.33	1.45	1.45	Propane
VOC	0.04	0.15	0.15	Propane
Lead	1.98E-06	8.66E-06	8.66E-06	Natural Gas

Recovery Technology Solutions, LLC
SIP Permit Application
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TABLE B.6.b - PROCESS HEATER (SOURCE CODE H001) EMISSIONS CALCULATIONS - HAPs

Emission Unit: H001 Process Heater for Oil
Control Equipment: NA
Maximum Rated Boiler Capacity: 4.0 MMBtu/hr

Fuel Type	% Sulfur	% Ash	Heat Value	Units	Maximum Fuel Consumption Rate	Units
Natural Gas	0.2	Negligible	1,020	Btu/scf	34.6	10 ⁶ scf/yr
Propane	0.18	Negligible	91.5	MMBtu/10 ³ gal	386.0	10 ³ gal/yr

Natural gas: Heat value AP-42 Section 1.4 Table 1.4-1 (July 1998)
Propane: Heat value AP-42 Section 1.5 Table 1.5-1 (July 2008)

Sulfur AP-42 Section 1.4 Table 1.4-2 (July 1998)
Sulfur AP-42 Section 1.5 Table 1.5-1 (July 2008)

Note: There are no HAP emission factors available in AP-42 Section 1.5 for Propane (backup fuel).

Calculations Summary - Primary Fuel : Natural Gas

HAP Name [CAS]	Uncontrolled Emission Factor ¹ (lbs/10 ⁶ scf)	Uncontrolled Emission Rate (lbs/hr)	Maximum Uncontrolled Emissions (tons/yr)	Pollution Control Efficiency (%)	Controlled Emission Factor (lbs/10 ⁶ scf)	Maximum Controlled Emissions (tons/yr)
Arsenic [7440-38-2]	2.00E-04	7.91E-07	3.46E-06	0.00%	NA	3.46E-06
Benzene [71-43-2]	2.10E-03	8.30E-06	3.64E-05	0.00%	NA	3.64E-05
Beryllium [7440-41-7]	1.20E-05	4.74E-08	2.08E-07	0.00%	NA	2.08E-07
Cadmium [7440-43-9]	1.10E-03	4.35E-06	1.90E-05	0.00%	NA	1.90E-05
Chromium [7440-47-3]	1.40E-03	5.53E-06	2.42E-05	0.00%	NA	2.42E-05
Cobalt [7440-48-4]	8.40E-05	3.32E-07	1.45E-06	0.00%	NA	1.45E-06
Dichlorobenzene [25321-22-6]	1.20E-03	4.74E-06	2.08E-05	0.00%	NA	2.08E-05
Formaldehyde [50-00-0]	7.50E-02	2.96E-04	1.30E-03	0.00%	NA	1.30E-03
Hexane [110-54-3]	1.80E+00	7.12E-03	3.12E-02	0.00%	NA	3.12E-02
Manganese [7439-96-5]	3.80E-04	1.50E-06	6.58E-06	0.00%	NA	6.58E-06
Mercury [7439-97-6]	2.60E-04	1.03E-06	4.50E-06	0.00%	NA	4.50E-06
Naphthalene [91-20-3]	6.10E-04	2.41E-06	1.06E-05	0.00%	NA	1.06E-05
Nickel [7440-02-0]	2.10E-03	8.30E-06	3.64E-05	0.00%	NA	3.64E-05
POM ²	6.98E-04	2.76E-06	1.21E-05	0.00%	NA	1.21E-05
Selenium [7782-49-2]	2.40E-05	9.49E-08	4.16E-07	0.00%	NA	4.16E-07
Toluene [108-88-3]	3.40E-03	1.34E-05	5.89E-05	0.00%	NA	5.89E-05
Totals		7.46E-03	3.27E-02			3.27E-02

¹ Emission factors from AP-42 Section 1.4 (07/98)

² Total POM emission factor is equal to the sum of the individual POM compounds and includes Naphthalene. Naphthalene is not double counted in the total HAPs.

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TABLE B.6.c - PROCESS HEATER (SOURCE CODE H001) EMISSIONS CALCULATIONS - GHGs

Emission Unit: H001 Process Heater for Oil
Control Equipment: NA
Maximum Rated Boiler Capacity: 4.0 MMBtu/hr

Note - GHG Emission Factors from 40 CFR Part 98 Subpart C (GHG Mandatory Reporting Rule, Combustion)
GWP Conversion factors from Table A-1 to Subpart A of Part 98—Global Warming Potentials.

Primary Fuel:		Natural Gas			
GHG Pollutant	GWP	Emission Factor	PTE		
		(lb/MMBtu)	(lb/hr)	(tpy)	CO ₂ e (tpy)
CO ₂	1	116.89	471	2,064	2,064
CH ₄	21	2.20E-03	0.01	0.04	0.8
N ₂ O	310	2.20E-04	0.00	0.00	1.2
			Total GHG (CO ₂ e)		2,066

Primary Fuel:		Propane			
GHG Pollutant	GWP	Emission Factor	PTE		
		(lb/MMBtu)	(lb/hr)	(tpy)	CO ₂ e (tpy)
CO ₂	1	135.49	546	2,393	2,393
CH ₄	21	6.61E-03	0.03	0.12	2.5
N ₂ O	310	1.32E-03	0.01	0.02	7.2
			Total GHG (CO ₂ e)		2,403

Worst-Case Potential-to-Emit Summary			
GHG Pollutant	PTE		
	(lb/hr)	(tpy)	CO ₂ e (tpy)
CO ₂	546	2,393	2,393
CH ₄	0.03	0.12	2.45
N ₂ O	0.01	0.02	7.24
		Total GHG (CO ₂ e)	2,403

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TABLE B7 - EMERGENCY FIRE PUMP (SOURCE CODE FP01) EMISSIONS CALCULATIONS

The emergency fire pump engine will be used for emergency fire purposes only.
 Scheduled maintenance/testing will be limited to 100 hr per year.
 Potential emissions are estimated based on maximum 500 hours per year of operation.

Engine Power in hp 500 hp
 Fuel Type: Diesel
 Maximum Fuel Sulfur: 0.0015% S by weight
 Max Operating Hours: 500 hr/yr

The engine will be required to meet NSPS Subpart IIII emissions standards for NOx/NMHC, and PM.
 For other pollutants, emissions are based on AP-42 Section 3.3 (10/96):

CRITERIA POLLUTANTS

Pollutant	Emission Factor	Units	Convert to lb/hr	PTE (tons/yr)
NOx+NMHC	3.0	gr/hp-hr	3.3	0.83
CO	6.68E-03	lb/hp-hr	3.3	0.84
PM	0.15	gr/hp-hr	0.2	0.04
SO2	2.05E-03	lb/hp-hr	1.0	0.26
VOC	2.51E-03	lb/hp-hr	1.3	0.31

HAPs:

Pollutant	Emission Factor	Units	Convert to lb/hr	PTE (tons/yr)
Benzene	9.33E-04	lb/MMBtu	3.27E-03	8.16E-04
Toluene	4.09E-04	lb/MMBtu	1.43E-03	3.58E-04
Xylenes	2.85E-04	lb/MMBtu	9.98E-04	2.49E-04
Propylene	2.58E-03	lb/MMBtu	9.03E-03	2.26E-03
1,3 Butadiene	3.91E-05	lb/MMBtu	1.37E-04	3.42E-05
Formaldehyde	1.18E-03	lb/MMBtu	4.13E-03	1.03E-03
Acetaldehyde	7.67E-04	lb/MMBtu	2.68E-03	6.71E-04
Acrolein	9.25E-05	lb/MMBtu	3.24E-04	8.09E-05
Naphthalene	8.48E-05	lb/MMBtu	2.97E-04	7.42E-05
Acenaphthylene	5.06E-06	lb/MMBtu	1.77E-05	4.43E-06
Acenaphthene	1.42E-06	lb/MMBtu	4.97E-06	1.24E-06
Fluorene	2.92E-05	lb/MMBtu	1.02E-04	2.56E-05
Phenanthrene	2.94E-05	lb/MMBtu	1.03E-04	2.57E-05
Anthracene	1.87E-06	lb/MMBtu	6.55E-06	1.64E-06
Fluoranthene	7.61E-06	lb/MMBtu	2.66E-05	6.66E-06
Pyrene	4.78E-06	lb/MMBtu	1.67E-05	4.18E-06
Benzo(a)anthracene	1.68E-06	lb/MMBtu	5.88E-06	1.47E-06
Chrysene	3.53E-07	lb/MMBtu	1.24E-06	3.09E-07
Benzo(b)fluoranthene	9.91E-08	lb/MMBtu	3.47E-07	8.67E-08
Benzo(k)fluoranthene	1.55E-07	lb/MMBtu	5.43E-07	1.36E-07
Benzo(a)pyrene	1.88E-07	lb/MMBtu	6.58E-07	1.65E-07
Indeno(1,2,3-cd)pyrene	3.75E-07	lb/MMBtu	1.31E-06	3.28E-07
Dibenz(a,h)anthracene	5.83E-07	lb/MMBtu	2.04E-06	5.10E-07
Benzo(g,h,i)perylene	4.89E-07	lb/MMBtu	1.71E-06	4.28E-07
			TOTAL	5.65E-03

GHGs:

GHG Pollutant	Emission Factor	Units	Convert to lb/hr	PTE (tpy)	GWP	CO2e PTE (tpy)
CO2	1.15	lb/hp-hr	575.0	143.75	1	143.75
CH4	3.00E-03	kg/MMBtu	2.31E-02	5.8E-03	21	0.12
N2O	6.00E-04	kg/MMBtu	4.63E-03	1.2E-03	310	0.36
			Total GHG (CO2e)		144	

Notes:

1. PM10 and PM2.5 are assumed to be equal to the NSPS PM emission rate.
 2. To convert from lb/MMBtu to lb/hp-hr, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used.
 3. GHG Emission Factors from 40 CFR Part 98 Subpart C (GHG Mandatory Reporting Rule, Combustion)
- GWP Conversion factors from Table A-1 to Subpart A of Part 98—Global Warming Potentials.

APPENDIX C

TOXIC IMPACT ASSESSMENT

AIR TOXICS MODELING& IMPACT ASSESSMENT
Recovery Technology Solutions, LLC
325 Alabama Boulevard
Jackson, GA 30233

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1 EXECUTIVE SUMMARY

1.1 Overview

In December 2012, an Air Toxics Modeling & Impact Assessment, herein referred to as the “Assessment,” was conducted for the proposed Recovery Technology Solutions, LLC (RTS) facility to be located on 325 Alabama Boulevard, Jackson, Georgia. The purpose of the Assessment was to estimate the environmental impact of potential sources of toxic air pollutants. A toxic air pollutant is defined as any substance which may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard.

The Assessment involved the calculation of the Acceptable Ambient Concentration (AAC) of all toxic air pollutants generated at the facility, modeling of the predicted ambient impact, and comparing the modeled results with the toxic air pollutant AAC. Toluene is the only toxic pollutant emitted from the facility at above negligible level (0.2 tons/yr). Therefore, the impact of toluene emissions is assessed by comparing toluene’s Maximum Ground Level Concentration (MGLC) to its AAC.

The Assessment was performed in accordance with the Georgia Environmental Protection Division (EPD) Air Protection Branch approved protocol for conducting an Air Toxics Modeling & Impact Assessment (*i.e.*, *Georgia EPD Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions, revised June 21, 1998*). The SCREEN3 Plume Dispersion Model was used to predict the MGLC of each toxic air pollutant. SCREEN3 is a model developed by the U.S. EPA which provides conservative estimates of the MGLC for point, area, and volume sources. SCREEN3 is a screening version of a U.S EPA’s complex model referred to as the ISC3 model.

1.2 Summary of Results

The modeling results were compared to the AAC for toluene to assess its impact. The results are summarized in Table E-1 below.

Table E-1.
Summary of Modeling Results

Compound Name	CAS No.	Above AAC (Yes/No)	Percent of AAC(%)		
			15-minute	24-hour	Annual
Toluene	108-88-3	No	6.53%	na	8.95%

The modeled toluene concentration was well below its AAC, and accordingly, the facility passed the Assessment.

2 ASSESSMENT PROTOCOL

2.1 Emissions Data

Toluene emission rates are presented in Attachment 1 of this document. The emission rate was estimated using vendor specifications for the purposes of this analysis.

2.2 Modeling Guidelines

The modeling and impact assessment were performed according to the *Division's Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (revised June 21, 1998). The process of modeling and impact assessment was divided into several steps as described below:

- Development of an Acceptable Ambient Concentration (AAC).
- Screening-level assessment using the SCREEN3 computer model to predict the Maximum Ground Level Concentration (MGLC). The screening was performed according to the SCREEN3 Model User's Guide (EPA publication number 454/B-95-004). The most recent version (v. 96043) of the SCREEN3 model was used.
- Comparison of the predicted MGLC's to the AAC's.

2.3 Acceptable Ambient Pollutant Concentrations

An AAC must be developed for each toxic air pollutant and applicable averaging time. The AAC is based on current pollutant toxicity data adjusted for operating hours and risk factors, and is expressed as a mg/m^3 limit. For acute sensory irritants, an assessment must be made for both the 24 hour exposures and the short-term, 15-minute exposures.

EPD has an established priority schedule for pollutant toxicity data for the determination of AAC's as follows:

- Integrated Risk Information System (IRIS)
- OSHA Standards (PEL's) - 29 CFR Part 1910 Subpart Z
- American Congress of Governmental Industrial Hygienists (ACGIH) Recommendations (TLV's)
- NIOSH Recommended Standards (REL's)
- LD50 Toxicity Data

- Other Methods

The toxicity data for toluene and the calculated AAC's are shown in Attachment 1. The annual AAC is based on IRIS, while the 15-minute AAC's are based on the ceiling limits and short term exposure limits presented in the OSHA Standards, ACGIH Recommendations, or NIOSH Recommendations. Please note that according to the EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions*, if annual and ceiling limits are applicable, only those two limits are included in the analysis (i.e., no 24-hour AAC applies).

3 SCREEN3 MODELING

The latest version of the SCREEN model, SCREEN3 Version 96043, was used.

3.1 Modeling Protocol

The SCREEN3 modeling parameters were selected based on the proposed design of the facility. The facility will have two stacks S001 and S002. S001 is the stack for the vent header system, while S002 is the building vent stack which might contain trace amount of fugitive emissions from the process equipment housed inside the building. For this analysis, fugitive emissions were also assumed to be emitted through S001. This assumption is conservative because fugitive emissions from the process equipment will actually be emitted through the building vent stack (S002) which has a much higher flowrate of 24,500 cfm.

Additionally, the 3 km radius area around the facility location was analyzed for rural/urban land characteristics. Although the 3 km region did not satisfy the urban classification as deduced by the land use and population density procedure detailed in U.S.EPA's Permit Modeling Guidance (Appendix W); for conservative estimates the urban option was used for modeling. The modeling parameters for Stack S001 are listed in Table 3-1 below.

Table 3-1
SCREEN3 Modeling Parameters for Stack S001

Parameter	Value
Source Type	Point
Emission Rate (g/s)	0.126
Stack Ht (m)	16.98
Stack Diameter (m)	0.15
Modeled Flow Rate (ACFM)	20
Stack Temp (K)	293
Ambient Air Temp (K)	293
Urban/Rural Option	Urban
Building Downwash	No

3.2 MGLC Calculations and Compliance Evaluation

First, the one-hour MGLC was determined using SCREEN3. At a 1 lb/hr emission rate, the maximum one hour concentration was determined to be $0.08559 \mu\text{g}/\text{m}^3$. The one-hour-averaging-period MGLC for all modeled pollutants could then be determined by multiplying the emission rate for each given pollutant by the MGLC predicted by the model. As recommended by the EPD

guideline, the one-hour averaging period can be translated to other averaging periods using the following factors:

- To obtain a 15-minute averaging period, multiply the 1-hour MGLC by 1.32;
- To obtain a 24-hour averaging period, multiply the 1-hour MGLC by 0.40;
- To obtain an annual averaging period, multiply the 1-hour MGLC by 0.08

The calculated MGLC's were then compared to the AAC's for determining acceptability. The results indicate that the MGLC for toluene is well below its AAC. A comparison of the MGLC to the calculated AAC, along with a compliance analysis is shown in Attachment 1. A copy of the SCREEN3 model results is included as Attachment 2.

ATTACHMENT 1
SUMMARY OF TOXIC IMPACT ASSESSEMENT

Summary of Ambient Impact Assessment of Toxic Air Pollutant Emissions

Facility:

Recovery Technology Solutions (Stack S001)

Distance To Nearest Property Line:

0 ft

Source Type:

Point

Stack Height:

0.00

meters

55.7 ft

Inside Dia.

0.5 ft

16.98

meters

0.15

meters

Unit MGLC:

8.559E-02

mg/m3

at

60

meters from the source.

		A	B			C		D			E				F			G					
Compound Name	CAS No.	Emission Rate lb./hr.	RfC mg/m3	"C" or STEL mg/m3	TWA mg/m3	Safety Factor		AAC, mg/m3			SCREEN3 Modeling Results/MGLC, mg/m3				Acceptability of the Predicted MGLC/Ambient Impact			Data Base & Note	Pecent of AAC			HAP (Yes/No)	Requires Refined Analysis (Yes/No)
						STEL/"C"	TWA	15 Minutes	24 Hours	Annual	1 hour	15 minutes	24 Hours	Annual	15-minute Impact	24-hour Impact	Annual Impact		15-minute	24-hour	Annual		
						Toluene	108-88-3	65.34	5.00E+00	1130.55	na	10	100	1.13E+02	na	5.00E+00	5.59E+00	7.38E+00	na	4.47E-01	Acceptable	na	Acceptable

1.

To obtain the worst emission scenario, an annual emission time of 8,760 hours is used in the SCREEN3 modeling as public exposure time, i.e., weekly emission occurs more than 40 hours. As the result, there is no operating time limit while the TWAs are lowered by a ratio of 40/168 to account for the longest public pollutant exposure according to Ta = To(40/X).
2.

A unit emission rate, i.e. 1.0 pound per hour should be used in the SCREEN3 modeling to obtain a unit MGLC. The MGLCs of the toxic compounds involved are obtained by scaling up or down from the unit MGLC using the ratios between the emission rates of those compounds and the unit emission rate.
3.

Input appropriate data only in the colored area. When such data are unavailable or unnecessary, input either "na" or "NA" instead to allow the spreadsheet to carry out correct calculations and logic judgements.
4.

The spreadsheet is protected from any accidental erase or change of the formulas or logic statements. To remove the protection, open "Tools" manual, chose "Protection", then "Unprotect sheet ..." (no password will be asked).

ATTACHMENT 2

MODEL RESULTS

12/17/12
15:28:40*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

RTS Stack S001

SIMPLE TERRAIN INPUTS:

SOURCE TYPE = POINT
 EMISSION RATE (G/S) = .126000
 STACK HEIGHT (M) = 16.9800
 STK INSIDE DIAM (M) = .1500
 STK EXIT VELOCITY (M/S) = .5341
 STK GAS EXIT TEMP (K) = 293.0000
 AMBIENT AIR TEMP (K) = 293.0000
 RECEPTOR HEIGHT (M) = .0000
 URBAN/RURAL OPTION = URBAN
 BUILDING HEIGHT (M) = .0000
 MIN HORIZ BLDG DIM (M) = .0000
 MAX HORIZ BLDG DIM (M) = .0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

STACK EXIT VELOCITY WAS CALCULATED FROM
 VOLUME FLOW RATE = 20.000000 (ACFM)

BUOY. FLUX = .000 M**4/S**3; MOM. FLUX = .002 M**4/S**2.

*** FULL METEOROLOGY ***

 *** SCREEN AUTOMATED DISTANCES ***

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
1.	.0000	1	1.0	1.1	320.0	16.90	.32	.24	NO
100.	76.78	4	1.0	1.1	320.0	16.88	15.69	13.79	NO
200.	55.91	5	1.0	1.2	10000.0	16.87	21.17	14.03	NO
300.	38.48	5	1.0	1.2	10000.0	16.87	31.18	19.93	NO
400.	26.51	5	1.0	1.2	10000.0	16.87	40.85	25.30	NO
500.	19.29	5	1.0	1.2	10000.0	16.87	50.21	30.24	NO
600.	14.74	5	1.0	1.2	10000.0	16.87	59.27	34.82	NO
700.	11.71	5	1.0	1.2	10000.0	16.87	68.06	39.11	NO
800.	9.591	5	1.0	1.2	10000.0	16.87	76.59	43.15	NO
900.	8.046	5	1.0	1.2	10000.0	16.87	84.89	46.97	NO
1000.	6.881	5	1.0	1.2	10000.0	16.87	92.97	50.60	NO
1100.	5.979	5	1.0	1.2	10000.0	16.87	100.83	54.06	NO
1200.	5.264	5	1.0	1.2	10000.0	16.87	108.50	57.37	NO
1300.	4.686	5	1.0	1.2	10000.0	16.87	115.99	60.55	NO
1400.	4.212	5	1.0	1.2	10000.0	16.87	123.30	63.61	NO
1500.	3.816	5	1.0	1.2	10000.0	16.87	130.44	66.56	NO
1600.	3.482	5	1.0	1.2	10000.0	16.87	137.43	69.42	NO
1700.	3.197	5	1.0	1.2	10000.0	16.87	144.27	72.18	NO
1800.	2.952	5	1.0	1.2	10000.0	16.87	150.97	74.86	NO
1900.	2.738	5	1.0	1.2	10000.0	16.87	157.54	77.47	NO
2000.	2.551	5	1.0	1.2	10000.0	16.87	163.98	80.00	NO
2100.	2.386	5	1.0	1.2	10000.0	16.87	170.30	82.47	NO
2200.	2.239	5	1.0	1.2	10000.0	16.87	176.50	84.87	NO
2300.	2.109	5	1.0	1.2	10000.0	16.87	182.59	87.22	NO
2400.	1.991	5	1.0	1.2	10000.0	16.87	188.57	89.52	NO
2500.	1.885	5	1.0	1.2	10000.0	16.87	194.45	91.77	NO
2600.	1.789	5	1.0	1.2	10000.0	16.87	200.24	93.96	NO
2700.	1.702	5	1.0	1.2	10000.0	16.87	205.93	96.12	NO
2800.	1.623	5	1.0	1.2	10000.0	16.87	211.54	98.23	NO
2900.	1.550	5	1.0	1.2	10000.0	16.87	217.05	100.30	NO
3000.	1.483	5	1.0	1.2	10000.0	16.87	222.49	102.34	NO
3500.	1.215	5	1.0	1.2	10000.0	16.87	248.52	112.00	NO
4000.	1.027	5	1.0	1.2	10000.0	16.87	272.88	120.95	NO
4500.	.8869	5	1.0	1.2	10000.0	16.87	295.82	129.32	NO
5000.	.7795	5	1.0	1.2	10000.0	16.87	317.54	137.20	NO
5500.	.6946	5	1.0	1.2	10000.0	16.87	338.21	144.67	NO
6000.	.6259	5	1.0	1.2	10000.0	16.87	357.94	151.79	NO
6500.	.5693	5	1.0	1.2	10000.0	16.87	376.84	158.60	NO
7000.	.5218	5	1.0	1.2	10000.0	16.87	395.00	165.14	NO
7500.	.4815	5	1.0	1.2	10000.0	16.87	412.50	171.43	NO
8000.	.4469	5	1.0	1.2	10000.0	16.87	429.40	177.50	NO
8500.	.4168	5	1.0	1.2	10000.0	16.87	445.74	183.38	NO
9000.	.3905	5	1.0	1.2	10000.0	16.87	461.59	189.08	NO
9500.	.3672	5	1.0	1.2	10000.0	16.87	476.98	194.62	NO
10000.	.3465	5	1.0	1.2	10000.0	16.87	491.93	200.00	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 1. M:
 60. 85.59 3 1.0 1.1 320.0 16.89 13.26 12.20 NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** SUMMARY OF SCREEN MODEL RESULTS ***

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
SIMPLE TERRAIN	85.59	60.	0.

** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **

APPENDIX D

CASE-BY-CASE MACT ANALYSIS

Case-by-Case MACT Analysis

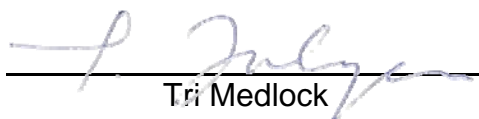
Prepared for:

Recovery Technology Solutions, LLC
Jackson, Georgia

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Tri Medlock
Associate

December 2012

**CASE-BY-CASE MACT ANALYSIS
RECOVERY TECHNOLOGY SOLUTIONS, LLC
Jackson, Georgia**

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ATTACHMENTS

Attachment A RBLC Search Results

1 INTRODUCTION

This document provides the required Case-by-Case MACT (Maximum Achievable Control Technology) Analysis to support Recovery Technology Solutions, LLC (RTS) air permit application for the proposed oil-based roofing material recycling facility in Jackson, Georgia (Butts County). The facility is to be permitted as a minor source with respect to Prevention of Significant Deterioration (PSD) pollutants, and a major source of hazardous air pollutants (HAPs). The primary HAP to be emitted from the facility is toluene at 286.2 tpy. Since the proposed facility is a new major source of HAPs and there is no applicable promulgated MACT, a Case-by-Case MACT determination under 112(g) of the Clean Air Act Amendments of 1990 is required. The requirements for a Case-by-Case MACT analysis are outlined in 40 CFR Part 63, Subpart B, *Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections 112(g) and 112(j)*. The U.S. EPA document *Preparing A Notice of MACT Approval Under 63.43(g) of 40 CFR 63, Subpart B Maximum Achievable Control Technology Emission Limitation for Constructed or Reconstructed Source* (July 8, 1999)¹ was used in preparing this Case-by-Case MACT Analysis.

¹ <http://www.epa.gov/ttn/atw/112g/noma1.pdf>

2 GENERAL SITE INFORMATION

The following information is included in this application in accordance with the requirements of 40 CFR 63.43(e)(2).

- i. *The name and address (physical location) of the major source to be constructed or reconstructed;*

Street Address: 325 Alabama Boulevard, Jackson, GA 30233 (Butts County)

Mailing Address: 325 Alabama Boulevard, Jackson, GA 30233 (Butts County)

Longitude/Latitude: 33° 17' 1.2881" North / -83° 57' 14.6382" West

- ii. *A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included;*

RTS proposes to construct and operate an oil-based roofing material recycling facility in Jackson, Georgia. The proposed facility is designed to process up to 250 tons per day of oil-based roofing materials including asphalt shingles and various oil-based flat-roof materials.

The typical roofing shingles are composed of approximately 20% fiberglass matting, 25% asphalt oil, 30% filler (sand), and 25% aggregate (rock, mineral granules). Flat-roof materials are typically composed of 80-85% oil and 15-20% fiberglass. In the recycling process, shingles and flat-roof materials are broken down into their basic components (asphalt oil, mineral granules, sand [calcium carbonates], and fiberglass) through extraction and separation. Markets for the facility's final products include the asphalt industry, pavement industry, landscape block manufacturers, fiberglass insulation companies and the concrete additives industry. RTS will partner with roofing material manufacturers, re-roofing contractors and waste management companies to allow them to reduce costly disposal fees while minimizing the amount of construction and demolition (C&D) waste being sent to landfills.

As mentioned above, the extraction, separation, and solvent recovery processes are not subject to any listed source categories as described in 40 CFR Part 63. Individual facility equipment is potentially subject to various National Emissions Standards for Hazardous Air Pollutants (NESHAP). Table 2.1 provides a list of HAP emission sources at the facility and potentially applicable NESHAP and New Source Performance Standards (NSPS).

Table 2.1
HAP Emission Sources at the Facility and Potentially Applicable Federal Regulations

HAP Emission Sources at the Facility	Potentially Applicable NESHAP Standard (40 CFR Part 63)	Potentially Applicable NSPS Standard (40 CFR Part 60)
Extraction, Separation, and Solvent Recovery Process Equipment (Source ID GP01)	None Promulgated	Subpart UUU (Not Applicable)
Toluene Storage Tank* (Source Code ST01)	Subpart EEEE	Subpart Kb (exempt)
Asphalt Oil Storage Tank (Source Code ST03)	None Promulgated	Subpart Kb (exempt)
Solvent Work Tank* (Source Code ST04)	Subpart EEEE (exempt)	Subpart Kb (exempt)
Boiler 1 (Source Code B001)	Subpart DDDDD	Subpart Dc
Process Heater 1 (Source Code H001)	Subpart DDDDD	Subpart Dc (exempt)
Fire Pump 1 (Source Code FP1)	Subpart ZZZZ	Subpart IIII

*Electively included as affected source for this Case-by-Case MACT Analysis

As shown in Table 2.1, the MACT-affected emission units (i.e.: “affected source” as defined in 40 CFR 63.2) subject to a Case-by-Case MACT analysis would be GP01 and ST03. Note that the facility electively includes storage tanks ST01 and ST04 as part of the affected source even though they may be subject to or specifically exempt from NESHAP Subpart EEEE.

- iii. *The expected commencement date for the construction or reconstruction of the major source*
2nd Quarter 2014
- iv. *The expected completion date for construction or reconstruction of the major source*
4th Quarter 2014
- v. *The anticipated date of start-up for the constructed or reconstructed major source*
4th Quarter 2014

3 MACT STANDARDS

3.1 Solvent Loss Cap

RTS proposes a solvent loss cap of 0.9 gallons per ton of roofing material processed as described in Section 3.4.5. No cap on material (solvent) usage is proposed. Compliance with the proposed solvent loss cap will be achieved by utilizing a solvent recovery system that is designed to maximize solvent (toluene) recovery. All recovered solvent will be reused in the process. Furthermore, the solvent recovery system equipment is considered inherent process equipment, rather than an air pollution control device because the recovery of toluene is essential for process safety (due to flammability of the solvent) and economics of the project.

3.2 Raw Material Requirements

Toluene has been selected as the preferred solvent for this novel oil extraction process by the design vendor based on research and pilot-scale development. The selection of toluene was based on feasibility, product quality and cost effectiveness of the roofing material oil extraction process.

Toluene is an organic solvent commonly produced from refining crude oil during the production of gasoline. It is a common industrial solvent widely used for paints, paint thinners, cleaning solvents, fuel additives, and other chemical and manufacturing processes. Industrial and commercial use of toluene has increased in past years, as it is a practical replacement for benzene (benzene is classified as a human carcinogen). Gasoline contains approximately 5 to 7 percent toluene, so toluene is a common airborne emission from fuel storage and transportation, and combustion use.

Consideration and testing of other solvents was conducted during various stages of the research and development work on this oil extraction process. Other solvents considered include:

- Hexane: Hexane is the primary solvent used in oilseed extraction; however, it does not dissolve oil in roofing material as effectively as toluene. Replacing toluene with hexane would increase the solvent requirement by approximately four times. Consequently, utility consumption (steam and electrical) to store, handle, and distill this additional solvent volume would increase proportionately. In addition, process and storage equipment would need to be increased in size. Therefore, emissions losses are expected to increase as well due to the increased volume of solvent handled.
- MCI – Methylene Chloride: MCI is a solvent/thinner used in paints, aerosol propellant, and insecticide. MCI is classified as a probable human carcinogen. This solvent also does not dissolve oil in roofing material as effectively as toluene. Replacing toluene with MCI would increase the solvent requirement by approximately 1.5 times. Furthermore, MCI

has a relatively low boiling point which would require refrigeration of the condensing systems.

- TCE – Trichloroethylene: TCE is a common degreaser and anesthetic. TCE is also commonly used for cutting and dissolving oil for testing purposes. For example, American Society for Testing and Materials (ASTM) specifications for oil properties utilize TCE for solubility testing. However, TCE is heavier than water, which complicates the process waste water separation and distillation process. It is also considered a possible human carcinogen.
- Acetone: Acetone is a solvent commonly found in nail polish remover, and used in plastics production, fiberglass and epoxies. Acetone has a very poor ability to dissolve oil.
- Vertrel (DuPont): Vertrel is very expensive, and its performance in the oil extraction process is similar to that of hexane. In addition, Vertrel is not readily available in quantities needed for this process.
- Xylene: Xylene is used in plastics, fuels, paints, and thinners. Xylene does not dissolve oil in roofing material as effectively as toluene. Replacing toluene with xylene would increase the solvent requirement by approximately 1.5 times. Xylene also has a higher boiling point than toluene, which increases the difficulty of desolventizing oil because it requires more heat, and therefore, a higher steam pressure. Also, xylene is problematic as it degrades commonly used gasket and hose materials.

In conclusion, after consideration and testing of other solvents, toluene was selected as the preferred solvent in the roofing material oil extraction process.

3.3 Process Changes

As this is the first plant of its kind, process changes for MACT are not applicable. The solvent recovery technology proposed represents the highest level of recovery known for this type of process at this time.

3.4 Add-On Controls

EPA document *Guidelines for MACT Determinations Under Section 112(j) Requirements* (February 2002)² was used to develop the MACT add-on control analysis. This document specifies a tiered approach for conducting a MACT analysis as follows:

Tier I

1. Identify the MACT-affected emission unit(s)
2. Make a MACT floor finding

² <http://www.epa.gov/ttn/atw/112j/guidance.pdf>

If the floor can be determined, proceed to Tier III. If the floor cannot be determined, proceed to Tier II.

Tier II

1. List all available/reasonable applicable control technologies
2. Eliminate technically infeasible control technologies
3. Determine efficiency of applicable control technologies

Tier III

1. Identify maximum emission reduction control technology
2. Conduct an impacts analysis
3. Establish the MACT emission limitation

As mentioned above, there is no relevant NESHAP standard currently promulgated for the roofing material oil extraction industry and no actual process data or historical examples of control equipment available. Therefore, there are no direct comparisons that can be made pursuant to 40 CFR 63.43(d)(4). However, because the facility's processes and equipment are similar to those of oilseed extraction facilities, parallel comparisons were made to NESHAP Subpart GGGG – Solvent Extractions for Vegetable Oil Production where appropriate.

3.4.1 Step 1 – Identify the MACT-Affected Emission Units

As shown in Table 2.1, the MACT-affected emission units (i.e.: “affected source”) are Emission Group GP01, ST01, ST03, and ST04. The affected source emits toluene at a potential emission rate of 286.2 tpy. See Appendix B for emissions summary and Appendix E for emissions references.

3.4.2 Step 2 – Make a MACT Floor Finding

As mentioned above, there is no relevant NESHAP standard currently promulgated for the roofing material oil extraction process, and no actual process data or historical examples of control equipment available. Therefore, there are no direct comparisons that can be made pursuant to 40 CFR 63.43(d)(4). A review of the RBLC database was conducted to determine a MACT floor which is defined in §63.51 as follows:

Maximum Achievable Control Technology (MACT) floor means:

- (2) For new sources, the emission limitation achieved in practice by the best controlled similar source.

The RBLC search covered entries from January 1, 2002 to November 1, 2012 within Process Code 70.300 (Vegetable Oil Manufacturing) and 70.650 (Soybean Oil Manufacturing). The Vegetable Oil Manufacturing and Soybean Oil Manufacturing processes are determined to be similar sources (as defined in §63.51) for this Case-by-Case MACT analysis:

Similar source means that equipment or collection of equipment that, by virtue of its structure, operability, type of emissions and volume and concentration of emissions, is

Process Code	RBL Record	Facility	Permit Date	Process	Throughput	Pollutant	Emission Limit	Basis	Control	Control Efficiency
70.350	NE-0048	Archer Daniels Midland-Fremont	10/29/2008	SOE	-	VOC	0.165 lb/ton	Other: Case-by-case	USE OF MINERAL OIL SCRUBBER, LEAK DETECTION AND REPAIR PROGRAM	N/A
70.350	IA-0094	Archer Daniels Midland	4/7/2008	DT	250 tpy	VOC	0.1712 gal/ton	BACT-PSD	MINERAL OIL ABSORBER	96%
70.350	MO-0073	AG Processing Inc.	5/16/2007	SPP	120,000 bushels/day	VOC	523.96 tpy	BACT-PSD	CONDENSER(S) AND A MINERAL OIL ABSORPTION SYSTEM AS SPECIFIED IN THE PERMIT APPLICATION	N/A
70.350	IA-0085	Bunge North America	1/29/2007	SOE	224,000 bushels/day	VOC	0.178 gal/ton	BACT-PSD	MINERAL OIL ABSORBER, LEAK PREVENTION	99%
70.350	MN-0065	Mankato	6/28/2005	SOE	-	Hexane	0.15 gal/ton oil, 245375.0000 T/YR	BACT-PSD	MAIN VENT HAS A CONDENSER WITH A MINERAL OIL ABSORBER AND LDAR.	N/A
70.350	OH-0282	Cargill Oilseeds Division	11/28/2003	SOE w/ DT	4500 tpd	VOC	792 tpy, 1.0000 COMPLIANCE RATIO FROM MACT	BACT-PSD	CONDENSER AND MINERAL OIL SCRUBBER TO CONTROL HEXANE	N/A
70.350	OH-0282	Cargill Oilseeds Division	11/28/2003	SFD	4,400 lb/hr	VOC	0.33 lb/hr, 1.4500 T/ROLLING 12-MO	BACT-PSD	N/A	N/A
70.350	OH-0282	Cargill Oilseeds Division	11/28/2003	SD	5,600 lb/hr soy	VOC	0.63 lb/hr, 2.7500 T/ROLLING 12-MO	BACT-PSD	N/A	N/A
70.350	IL-0072	Viobin	2/11/2002	Ext	50 tpd	Hexane	0.9000 GAL HAP/T SEED PROC	MACT	MINERAL OIL SCRUBBER	N/A

Notes: DT = Desolventizer Toaster; SOE = Soybean Oil Extraction; SPP = Soybean Processing Plant; SFD = Spent Flake Dryer; SD = Spray Dryer; Ext = Extractor

As shown in the table above, the applicable add-on control equipment is a condenser with a mineral oil absorber. Therefore, installation of a process condenser and mineral oil scrubber established the MACT floor for this analysis. Note that RTS considers the process condenser and mineral oil scrubber system (part of the vent header system) as inherent process equipment because toluene recovered from the system is reused in the process and the recovery rate is essential for the economics of the facility.

Additionally, as part of Best Management Practices (BMP), RTS will implement a Leak Detection and Repair (LDAR) program. The LDAR program will include routine visual inspection and instrument monitoring. RTS will define the type of equipment to monitor, monitoring frequency, monitoring method (e.g.: EPA Method 21), and repair requirements. LDAR records will be kept onsite.

3.4.3 Step 3 – Identify Maximum Emissions Reduction Control Technology

Based on the EPA Air Pollution Control technology Fact Sheet³, VOC removal efficiencies for gas absorbers are normally in excess of 90%, depending on the pollutant-solvent system and the type of absorber used. The typical collection efficiency range from 50% to 95% with lower control efficiencies represent flows containing relatively insoluble compounds at low concentrations, while the higher efficiencies are for flows which contain readily soluble compounds at high concentrations. Therefore, the use of the mineral oil scrubber with expected solvent recovery efficiency of 95% will represent the maximum emissions reduction control technology. Although this level of control is less than the level of control proposed by AG Processing Sergeant Bluff (RBL Record IA-0103) for control of VOC, as there are no reported instances which could be found of a control technology established for control of toluene from a roofing material oil extraction process, 95% solvent recovery efficiency is proposed as sufficient to satisfy MACT.

3.4.4 Step 4 – Conduct an Impact Analysis

As stated in the U.S. EPA document *Guidelines for MACT Determinations Under Section 112(j) Requirements*:

Section 112(d) of the Act specifies that if control technology alternatives are being considered to establish an emission standard that would result in emission limitations more stringent than the emission "floors," they must be evaluated by considering costs, non-air quality health and environmental impacts, and energy requirements associated with the expected emission reductions.

Since the MACT floor has been established and accepted by RTS, an impact analysis is not necessary. No beyond the floor technologies are anticipated that would be used to effectively provide sufficient secondary reduction of toluene. The MACT floor level established the selected control technology that will provide the maximum degree of reduction of toluene emissions.

³ <http://www.epa.gov/ttn/catc/dir1/fsptrytwr.pdf>

Therefore, no “beyond-the-floor” technologies are anticipated that would require an assessment of energy, economic, or environmental impacts.

3.4.5 Step 5 – Establish MACT Emission Limitation

The proposed MACT emission limit for RTS is a solvent loss cap of 0.9 gallons of toluene per ton of roofing material processed (see section 3.1). The proposed limit was developed based on promulgated NESHAPs for similar sources (i.e. NESHAP Subpart GGGG – Solvent Extraction for Vegetable Oil Production). Table 1 of NESHAP Subpart GGGG (reproduced below) provides the allowable HAP loss for the source category.

**Table 3.2. Table 1 of § 63.2840
Oilseed Solvent Loss Factors for Determining Allowable HAP Loss**

Type of oilseed process	A source that...	Oilseed solvent loss factor (gal/ton)	
		Existing sources	New sources
(i) Corn Germ, Wet Milling	processes corn germ that has been separated from other corn components using a “wet” process of centrifuging a slurry steeped in a dilute sulfurous acid solution	0.4	0.3
(ii) Corn Germ, Dry Milling	processes corn germ that has been separated from the other corn components using a “dry” process of mechanical chafing and air sifting	0.7	0.7
(iii) Cottonseed, Large	processes 120,000 tons or more of a combination of cottonseed and other listed oilseeds during all normal operating periods in a 12 operating month period	0.5	0.4
(iv) Cottonseed, Small	processes less than 120,000 tons of a combination of cottonseed and other listed oilseeds during all normal operating periods in a 12 operating month period	0.7	0.4
(v) Flax	processes flax	0.6	0.6
(vi) Peanuts	processes peanuts	1.2	0.7
(vii) Rapeseed	processes rapeseed	0.7	0.3
(viii) Safflower	processes safflower	0.7	0.7
(ix) Soybean, Conventional	uses a conventional style desolventizer to produce crude soybean oil products and soybean animal feed products	0.2	0.2
(x) Soybean, Specialty	uses a special style desolventizer to produce soybean meal products for human and animal consumption	1.7	1.5
(xi) Soybean, Combination Plant with Low Specialty Production	processes soybeans in both specialty and conventional desolventizers and the quantity of soybeans processed in specialty desolventizers during normal operating periods is less than 3.3 percent of total soybeans processed during all normal operating periods in a 12 operating month period. The corresponding solvent loss factor is an overall value and applies to the total quantity of soybeans processed.	0.25	0.25
(xii) Sunflower	processes sunflower	0.4	0.3

As shown above, the allowable solvent loss factor for new oilseed sources ranges from 0.2 gal/ton (for conventional oilseed process) to 1.5 gal/ton (for specialty oilseed process). The proposed MACT emission limit of 0.9 gal/ton solvent loss is appropriate for RTS because of the following differences between the roofing material oil extraction process and the oilseed process:

- Differences in material (oilseed vs. ground roofing material) and solvent (hexane vs. toluene) will affect the solvent recovery rate between the two processes. Note that hexane is relatively insoluble in water, while toluene is somewhat soluble in water. This requires an extra step in the roofing material processing to remove toluene emissions from process water that is not required for hexane recovery in oilseed processing.
- Differences in production scale of the plant. The proposed plant is considered small in comparison with typical oilseed recovery facilities. Therefore, a higher solvent loss rate is expected from the proposed facility (the smaller facility). Higher solvent loss rates in smaller facilities are also consistent with the solvent loss rates in NESHAP Subpart GGGG where smaller specialty processes have a higher allowable solvent loss rate than conventional large scale processes. For example, the solvent loss limit for conventional oilseed plants is 0.2 gallons per ton of oilseed processed; whereas the solvent loss limit for oilseed specialty plants is 1.5 gallons per ton of oilseed processed.

3.5 Reduce Material, Storage, and Handling Emissions

The extraction process is designed to be vapor tight. The facility's primary incentive to minimize solvent loss is to achieve high quality final products, as more solvent in the final product reduces its overall quality. The facility also has an incentive to recover as much solvent as possible to reduce the quantity of fresh solvent that needs to be purchased. The process equipment is designed to maximize toluene recycling and reuse in the process system. Additionally, RTS will implement an LDAR program (see section 3.4.2).

3.6 Implement and Operator Training Course

The facility is anticipated to employ approximately 18 persons. RTS will train all personnel, including contract personnel, who are involved in process operations, maintenance, and loading operations, to practice BMP for minimizing solvent loss in the process.

4 COMPLIANCE DEMONSTRATIONS, PERFORMANCE TESTING, AND MONITORING REQUIREMENTS

This section was developed following NESHAP Subpart GGGG requirements.

4.1 Initial Compliance Demonstration

RTS will submit an initial notification for new sources and appropriate notification of compliance status. The compliance date is the startup date of the facility. Additionally, there will be an initial startup period⁴ which can last for up to six calendar months. During the initial startup period, RTS will meet the requirements and schedules for demonstrating compliance for a new source operating under an initial startup period.

RTS will notify the Georgia EPD of the actual date of startup within 15 calendar days. The compliance plan will provide detailed procedures to monitor and record data necessary for demonstrating compliance. The plan will be kept onsite for the operating life of the facility. If any changes are made, previous versions of the plan will be kept and made readily available for five years. The plan will include the following:

1. Name and address of the owner or operator.
2. Physical address of the process.
3. Detailed description of all methods of measurement used to determine solvent losses and the tons of roofing material processed.
4. When each measurement will be made.
5. Examples of the calculations used to determine compliance status.
6. Example logs of how data will be recorded.
7. Plan to ensure the data continue to meet compliance demonstration needs.

Table 4.1 below summarizes the proposed compliance demonstration requirements.

⁴ For Reference Only: In NESHAP Subpart GGGG § 63.2872, *Initial startup period* means a period of time from the initial startup date of a new, reconstructed or significantly modified source, for which you choose to operate the source under an initial startup period subject to § 63.2850(c)(2) or (d)(2). During an initial startup period, a source complies with the standards by minimizing HAP emissions to the extent practical. The initial startup period following initial startup of a new or reconstructed source may not exceed 6 calendar months. The initial startup period following a significant modification may not exceed 3 calendar months. Solvent and oilseed inventory information recorded during the initial startup period is excluded from use in any compliance ratio determinations.

Table 4.1 Requirements for Compliance with Solvent Loss Cap

RTS is required to...	For periods of normal operation?	For initial startup periods?
Operate and maintain the source in accordance with general duty provisions of §63.6(e).	Yes and HAP solvent loss cap also apply.	Yes, RTS is required to minimize emissions to the extent practicable throughout the initial startup period as described in the SSM Plan.
Determine and record the extraction solvent loss in gallons.	Yes	Yes
Record the volume fraction of HAP present at greater than 1 percent by volume and gallons of extraction solvent in shipment received.	Yes	Yes
Determine and record the tons of roofing material processed.	Yes	Yes
Determine the weighted average volume fraction of HAP in extraction solvent received by end of the following calendar month.	Yes	No, the HAP volume fraction in any solvent received during an initial startup period is included in the weighted average HAP determination for the next operating month.
Determine and record the actual solvent loss, weighted average volume fraction HAP, roofing material processed, and compliance ratio for each 12 month operating month period by the end of the following calendar month.	Yes	No, RTS is not required to determine the compliance ratio with data recorded for an initial startup period.
Submit a Notification of Compliance Status or Annual Compliance Certification.	Yes.	No.
Submit a Deviation Notification Report by the end of the calendar month following the month in which you determined that the compliance ratio exceeds 1.00.	Yes	No, since RTS is not required to determine the compliance ratio with data recorded for the initial startup period.
Submit a Periodic SSM* Report.	No, a SSM activity is not categorized as normal operation.	Yes
Submit an Immediate SSM* Report.	No, a SSM activity is not categorized as normal operation.	Yes, only if RTS does not follow the SSM Plan.

*See section 5 for SSM Plan discussion

4.2 Ongoing Compliance Demonstration

RTS will submit necessary ongoing compliance certification, as well as periodic SSM reports when process downtime is scheduled and immediate SSM reports when downtime is unscheduled and will result in increased air emissions. RTS will maintain all records and reports for a period of five years following the date of occurrence, measurement, corrective action, report, or record. Material usage, solvent loss and compliance ratios, and total throughput will be recorded. Recordkeeping will begin on the startup date of the facility. The first compliance ratio will be determined by the end of the calendar month following the first 12 operating months after termination of the initial startup period, which can last for 6 months. The first compliance ratio will be based on information recorded during the first 12 operating months after the initial startup period.

An operating month is a calendar month in which RTS processes roofing material and is not operating under an initial startup period or malfunction period. The 12-month compliance ratio may include operating months occurring prior to a source shutdown and operating months that follow after the source resumes operation. If the source shuts down and processes no roofing material for an entire calendar month, that month is categorized as a non-operating month. Any non-operating months will be excluded from the compliance ratio determination. During the initial startup period, any solvent and roofing material information recorded for the initial startup period will be excluded from the compliance ratio. Any solvent or roofing material information that occurred during a malfunction period will also be excluded from the compliance ratio determination. A malfunction, as defined in the 40 CFR 63 General Provisions, is any sudden, infrequent, and not reasonably preventable failure of process equipment or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

The MACT solvent loss cap will limit the number of gallons of toluene lost per ton of roofing material processed. For each operating month, RTS will calculate a compliance ratio using Equation 1 below to compare the actual HAP loss to the allowable HAP loss for the previous 12 operating months. If the compliance ratio calculated per Equation 1 is less than or equal to 1.00, RTS is in compliance with the solvent loss cap. An operating month is any calendar month in which RTS processes any quantity of roofing material, excluding any entire calendar month in which RTS operates under an initial startup period or under a malfunction period. An operating month may include time intervals characterized by several types of operating status. However, an operating month must have at least one normal operating period.

$$\text{Compliance Ratio} = \frac{\text{Actual Hap Loss}}{\text{Allowable Hap Loss}} \quad (\text{Eq. 1})$$

While RTS anticipates using 100 percent toluene as the solvent, it is possible that future solvent will contain chemicals that are not classified as HAPs. Equation 1 can be expressed as a function of total solvent loss as shown below in Equation 2.

$$\text{Compliance Ratio} = \frac{f * \text{Actual Solvent Loss}}{0.9 * \text{Roofing Material}} \quad (\text{Eq. 2})$$

Where:

f = The weighted average volume fraction of HAP in solvent received during the previous 12 operating months, dimensionless.

Actual Solvent Loss = Actual Solvent Loss calculated per Equation 4 below

0.9 = The solvent loss cap (gal/ton) required for MACT compliance.

Roofing Material = Tons of roofing material processed during the previous 12 operating months.

To determine the weighted average volume fraction of HAP in the actual solvent loss, RTS will record the volume fraction of each HAP comprising more than 1 percent by volume of the solvent in each solvent delivery. To determine HAP content, reference a material safety data sheet or a manufacturer's certificate of analysis. The weighted average volume fraction of HAP for an operating month includes all solvent received since the end of the last operating month, regardless of the operating status at the time of the delivery. Determine the monthly weighted average volume fraction of HAP by summing the products of the HAP volume fraction of each delivery and the volume of each delivery and dividing the sum by the total volume of all deliveries (see Equation 3 below). Record the result by the end of each calendar month following an operating month.

$$\begin{aligned} & \text{12-Month Weighted Average of HAP Content in Solvent Received (volume fraction)} \\ &= \frac{\sum_{i=1}^n (\text{Received}_i * \text{Content}_i)}{\text{Total Received}} \quad (\text{Eq. 3}) \end{aligned}$$

Where:

Received_i = Gallons of extraction solvent received in delivery "i"

Content_i = Volume fraction of HAP in extraction solvent delivery "i".

Total received = Total gallons of extraction solvent received since the end of the previous operating month.

n = Number of extraction solvent deliveries since the end of the previous operating month.

When RTS has processed roofing materials for 12 operating months, sum the products of the monthly weighted average HAP volume fraction and corresponding volume of solvent received and divide by the total volume of solvent received for the 12 operating months. Record the result by the end of each calendar month and use in Equation 2 to determine the compliance ratio.

Actual solvent loss will be calculated for normal operating months. RTS will measure and record the solvent inventory on the beginning and ending dates of each normal operating period that occurs during an operating month. Solvent inventory will only be measured and recorded when the facility is processing roofing material to avoid artificially inflating the solvent inventory when transferring solvent to storage tanks. The total gallons of toluene received in each shipment

will be recorded. As the process recycles and recovers toluene, the quantity of recovered toluene will be quantified and included in the gallons of toluene received. Solvent inventory may be adjusted when necessary with reasonable justification. Reasonable justification may include changes in solvent working capacity.

$$\text{Monthly Solvent Loss (gal)} = \sum_{i=1}^n (SOLV_B - SOLV_E + SOLV_R \pm SOLV_A)_i \quad (Eq. 4)$$

Where:

- SOLV_B = Gallons of toluene in the inventory at the beginning of a normal operating month
- SOLV_E = Gallons of toluene in the inventory at the end of a normal operating month
- SOLV_R = Gallons of toluene received between the beginning and ending inventory dates of a normal operating month.
- SOLV_A = Gallons of toluene added or removed from the inventory.

The actual solvent loss is the total solvent losses during the normal operating periods for the previous 12 operating months. RTS will record the actual solvent loss by the end of each calendar month following an operating month and use it to calculate the compliance ratio. If there is no roofing material processed during the month, there is no compliance ratio determination.

4.3 Performance Testing

RTS will not conduct performance testing. Compliance with the MACT solvent loss cap is determined based on the quantity of solvent lost. No solvent is being destroyed, so there is no control efficiency testing to be conducted.

5 REPORTING AND RECORDKEEPING REQUIREMENTS

5.1 Initial Compliance Certification

RTS will submit initial notification of the actual startup date of the facility within 15 days of that startup date. The initial notification of compliance status will be consistent with the 40 CFR 63 Subpart A- General Provisions.

5.2 Ongoing Compliance Certification

Consistent with 40 CFR 63, Subpart A - General Provisions, RTS will submit ongoing annual compliance certifications. The certifications will include any periods of noncompliance and actions taken to come back into compliance.

5.3 Notice of Failure to Follow Plans

RTS plans on following its SSM Plan. In the event that the SSM Plan is not followed, RTS will provide the required notifications. See Section 6.1 for details on SSM Plan.

5.4 Record Retention

RTS will maintain all records and reports in a form suitable and readily available for inspection and review. The reports and records shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

5.5 Required Records

RTS will keep the records needed to document compliance demonstrations. These records include material usage records, production records, HAP content of solvent used, employee training records, source test results, and emissions data.

6 MAINTENANCE REQUIREMENTS

This section was developed following NESHAP Subpart GGGG requirements.

6.1 Startup, Shutdown and Malfunction Plan

RTS will prepare and implement a startup, shutdown, and malfunction (SSM) plan that complies with §63.6(e) of the 40 CFR 63 General Provisions. It will provide detailed procedures for operating and maintaining the facility to minimize emissions during a qualifying SSM event. The SSM Plan will specify a program of corrective action for malfunctioning process equipment and reflect the best practices to minimize emissions. Some or all of the procedures may come from other plans, such as a Standard Operating Procedure manual or an Occupational Safety and Health Administration (OSHA) Process Safety Management plan.

Due to the fugitive emissions of toluene associated with the extraction process equipment, the difficulty in quantifying the volume of toluene that is in the process at any given time, and the unexpected nature of process failures, capturing and measuring solvent loss during periods of SSM would be infeasible and would likely result in measurement errors. Since emissions from SSM events cannot be accurately quantified, it is not appropriate to set numeric limits during periods of SSM. For this reason, Work Practice Standards (WPS) are appropriate because measuring emission levels during SSM events is technical and economically impracticable, and thus compliance with an emission limit cannot be demonstrated.

The SSM Plan will include the following WPS:

1. Operate equipment in a manner consistent with good air pollution control practices at all times, including SSM.
2. Minimize idle or startup time.
3. Follow manufacturer maintenance requirements.
4. Ensure that employees are trained in SSM procedures including maintenance and cleaning, safety, mineral oil system startup, and procedures to minimize emissions and fugitive leaks.
5. Maintain records of startup and shutdown as well as the reason for the event.

At all times, including periods of startup, shutdown, and malfunction, RTS will operate and maintain the affected source in a manner consistent with good air pollution control practices for minimizing emissions. The SSM Plan and records will be kept onsite.

A malfunction, as defined in the 40 CFR 63 General Provisions, is any sudden, infrequent, and not reasonably preventable failure of process equipment or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions. If the facility continues to operate during a malfunction

(including the period reasonably necessary to correct the malfunction), or starts up after a shutdown resulting from a malfunction, they must meet compliance requirements. Within 15 days of the beginning of the malfunction, RTS must comply with either normal operating period requirements or with malfunction period requirements. At the end of the malfunction period, RTS will comply with normal operation requirements.

6.2 Operator Training Program

RTS will develop an operator training program for all personnel and will record the training date for all operators. The training program will be designed to include appropriate equipment operation practices and operation and maintenance of the air pollution control equipment to minimize solvent emissions. The operating training program and records will be kept onsite.

ATTACHMENT A
RBLC Search Results

Report Date: 11/01/2012 INDEX OF CONTROL TECHNOLOGIES DETERMINATIONS

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

Company Name	RBLC ID	Country	Permit Date(Est/Act)	Process Type	Process Description
SOUTH COUNCIL OIL MILL	OK-0138	USA	01/21/2010 ACT	70.300	Residual Crude Meal
				70.300	Process Wastewater
				70.300	Vegetable Oil Absorber
				70.300	Meal Pelletizer Dryer/Cooler
				70.300	Startup/Shutdown
				70.300	Residual Crude Oil Storage Tanks
				70.300	Solvent Storage Tanks
				70.300	Equipment Leaks
CARGILL, INC	*AL-0255	USA	05/18/2009 ACT	70.300	BOILER, HURST, WOOD-FIRED
6 SE 4TH STREET	OK-0125	USA	05/16/2008 ACT	70.300	DESOLVENTIZER TOASTER

Report Date: 11/01/2012 INDEX OF CONTROL TECHNOLOGIES DETERMINATIONS

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

Company Name	RBLC ID	Country	Permit Date(Est/Act)	Process Type	Process Description
AG PROCESSING SERGEANT BLUFF	IA-0103	USA	07/24/2012 ACT	70.350	Soybean oil extraction
ARCHER DANIELS MIDLAND - FREMO	NE-0048	USA	10/29/2008 ACT	70.350	SOYBEAN OIL EXTRACTION
ARCHER DANIELS MIDLAND	IA-0094	USA	04/07/2008 ACT	70.350	DESOLVENTIZER/TOASTER
AG PROCESSING INC	MO-0073	USA	05/16/2007 ACT	70.350	SOYBEAN PROCESSING PLANT
BUNGE NORTH AMERICA	IA-0085	USA	01/29/2007 ACT	70.350	EXPANDER
				70.350	DRYER COOLER
				70.350	SOYBEAN OIL EXTRACTION
				70.350	FLAKER ASPIRATION
MANKATO	MN-0065	USA	06/28/2005 ACT	70.350	SOYBEAN OIL EXTRACTION
BUNGE NORTH AMERICA, INC.	IA-0075	USA	11/02/2004 ACT	70.350	MEAL STORAGE BIN
CARGILL OILSEEDS DIVISION	OH-0282	USA	11/28/2003 ACT	12.900	CRUSH PLANT BOILER W/ FUEL OIL #2/SOYBEAN OIL
				70.350	ISOLATE PLANT SOY PROTEIN SPRAY DRYER
				70.350	DRYER/ COOLER DECKS (SIX DECKS)
				70.350	GRAIN DRYERS (TWO)
				70.350	SOYBEAN OIL EXTRACTION W/ DESOLVENTIZERS
				70.350	SPENT FLAKE DRYER
				12.900	CRUSH PLANT BOILER W/ NATURAL GAS
				13.900	PROTEIN PLANT BOILERS (TWO) W/ NATURAL GAS
				13.900	PROTEIN PLANT BOILERS (TWO) W/ FUEL OIL #2/SOYBEAN OIL
ARCHER DANIELS MIDLAND CO. - K	*SC-0118	USA	11/14/2003 ACT	70.350	SOYBEAN OIL EXTRACTOR
ARCHER DANIELS MIDLAND CO. - K	SC-0119	USA	11/14/2003 ACT	70.350	SOYBEAN RAIL RECEIVING
CARGILL SIOUX CITY	IA-0069	USA	07/22/2003 ACT	70.350	BEAN DUST BAGFILTER, TANK 82
				70.350	WEST GRAIN CLEANER
VILOBIN	IL-0072	USA	02/11/2002 ACT	70.350	EXTRACTOR

APPENDIX E

EMISSIONS REFERENCES

EMISSIONS ESTIMATE CALCULATIONS
Rev C 6 Nov 12

RTS ASPHALT SHINGLE RECOVERY PROJECT

Revision A - 20 July 12

Revision B - 24 July 12

Revision C - 6 Nov 12

ASSUMPTIONS USED FOR EMISSIONS CALCULATIONS

Crown Iron Works is an equipment and process design supplier, primarily for the oilseed extraction industry. We have experience in designing equipment and the process to separate oils from solid material using organic solvents, dating back to the late 1940's. Crown is using this engineering knowledge and experience to develop the extraction process to recycle asphalt shingles, recovering the asphalt and solid material for re-use.

Although the shingle extraction concept has been proven in lab and pilot plant testing over several years of R&D, no production shingle recycling plants yet exist. This is to be a new commercial process for the recycling industry and the first plant to be built world-wide.

Because of this, we do not have measured emission rates for an existing production process, and we must therefore estimate the proposed emission rates based on engineering judgment and by comparison to the established oilseed extraction industry – which is a similar solvent extraction process in many respects.

The process has 4 designed discharge locations/emission points. Non-condensable gas, which is primarily air brought into the process, is discharged thru a vent fan. Process waste water, which is a combination of moisture from the incoming shingles and condensed direct contact steam (used for heating and stripping), is discharged to drain. Reclaimed asphalt is out-loaded for commercial sale/transportation. Solid material (aggregate/rock, sand, back-dust, and fiberglass) is out-loaded for commercial sale/transportation.

Solvent can be a component of each of these discharge streams, and there will be some solvent emission losses attributed to each.

AIR:

A portion of the air discharged from the process is brought in with the solid feed material. This air enters the Extractors with the ground shingles and is drawn out thru the vent system and discharged after passing thru the Mineral Oil System.

200 TON/DAY GROUND SHINGLE PROCESS RATE
APPROX 80 LB/FT³ DENSITY (GROUND SHINGLES)

$$200\text{T/D} \times 2000\text{ LBS/T} \times 0.0125\text{ FT}^3/\text{LB} \times 0.0007\text{ D/MIN} = 3.47\text{ FT}^3/\text{MIN}$$

APPROX 60% VOID SPACE (AIR) IN GROUND MATERIAL AT THE GIVEN BULK DENSITY

$$3.47\text{ FT}^3/\text{MIN} \times 0.60 = 2.08\text{ FT}^3/\text{MIN AIR ENTRAINED IN MATERIAL}$$

Due to the nature of the flammable solvent, based on NFPA 36, an air break is required in the conveying system between the preparation equipment and the solvent extraction equipment within the controlled area of the processing plant. The purpose of this is to ensure that solvent vapors (from an accidental leak) from the extractor do not travel down the inlet conveyor and enter the preparation equipment and building (non-explosion proof area).

A 2.0 factor is commonly used for Oilseed Extraction Plants to account for additional air brought into the system thru the Air Break.

$$2.08\text{ FT}^3/\text{MIN} \times 2.0 = 4.16\text{ FT}^3/\text{MIN}$$

The front end of this process is being fed by bucket loaders, which can cause interruptions in the material feed to the process. To account for interruptions in the feed stream, where no material is feeding into the process, an additional 1.50 factor is used.

$$4.16\text{ FT}^3/\text{MIN} \times 1.5 = 6.24\text{ FT}^3/\text{MIN AIR ENTERING THE PROCESS W/ THE FEED MATERIAL.}$$

Air is also drawn into the system at other points. The Desolventizer discharges solid material into an atmospheric pressure, non-vapor tight conveyor. The Desolventizer is under slight vacuum and will therefore draw in some air thru the discharge conveyor, which is then carried thru the distillation system and discharged thru the Mineral Oil Absorber. Based on the pressure drop across the discharge gate and the area of that opening reduced by the volume of the solid material flow thru it:

Estimate approximately 8.0 cfm air drawn in thru the Desolventizer discharge.

The high level vacuum system will generate air leaks into the process. This value is dependent on size and manufacturing tolerances of equipment covers, ducting, flanges and proper installation and maintenance of the gaskets and hardware. In consultation with the vacuum ejector manufacturer, and based on experience with high vacuum systems in use w/ similar equipment processes:

Estimate approx 6.0 cfm is drawn into the process thru the high vacuum system.

At ambient temperature and pressure, a measureable quantity of air is dissolved and remains in solution with both the solvent and asphalt. At higher temperatures and lower pressure (within the high vacuum system), an amount of this dissolved air is released from the liquids into the vapor streams.

Estimate approximately 1.0 cfm of dissolved air is released from the solvent and asphalt.

TOTAL POSSIBLE AIR ENTERING EXTRACTION PLANT WITH FEED MATERIAL

$$6.24 + 8 + 6 + 1 = 21.24 \text{ FT}^3/\text{MIN}$$

ESTIMATE A MAXIMUM TOLUENE CONCENTRATION IN THE DISCHARGE AIR STREAM OF 90% LEL.
LEL OF TOLUENE IS APPROX 1.27% BY VOLUME = 0.040 MASS RATIO IN AIR.

$$21.24 \text{ FT}^3/\text{MIN} \times 60 \text{ MIN}/\text{HR} \times 0.075 \text{ LBS}/\text{FT}^3 \text{ (AIR)} \times 0.040 \times 0.9 = 3.44 \text{ LBS}/\text{HR TOLUENE LOSS}$$

WATER

Process Waste Water is generated from direct contact (sparge) stripping steam used in the process and from moisture in the solid feed material.

DESOLVENTIZER SPARGE STEAM = 500 LBS/HR

MOS STRIPPER SPARGE STEAM = 120 LBS/HR

WATER/SOLVENT DISTILLATION STRIPPER SPARGE STEAM = 500 LBS/HR

VACUUM STEAM EJECTOR = 600 LBS/HR

THIN FILM EVAPORATOR PURGE = 300 LBS/HR

SPARGE STEAM TOTAL = 2020 LBS/HR

ASSUME MAXIMUM 6% MOISTURE IN THE FEED MATERIAL INTO THE EXTRACTOR. Water is used as cooling and dust control in the shingle grinding equipment (Rotochopper). Moisture in the discharged ground shingles can be as high as 15-20%. This material is fed thru a dryer to dry the material to a maximum of 6% moisture (limited by the airflow and heating capability of the dryer).

$200 \text{ T/D} \times 2000 \text{ LBS/T} \times 0.0417 \text{ HR/D} \times 0.06 = 1000 \text{ LBS/HR}$

TOTAL ESTIMATED PROCESS WASTE WATER = $2020 + 1000 = 3020 \text{ LBS/HR} = 6.03 \text{ GPM}$

Boiled toluene vapor and steam vapors are condensed into the liquid phase together in the various distillation system condensers. The liquids will flow together back to the solvent water separator side of the work tank, where the toluene and water mechanically separate (due to different specific gravities). Toluene and water are only slightly miscible (approx 0.047% by wt of toluene in water) so a trace amount of toluene will remain in the waste water stream that exits the work tank. This stream will be sent to a water distillation system to strip residual toluene from the waste water stream. Testing has shown that residual toluene in water after stripping can be reduced to approx 25 ppm.

ASSUME A MAXIMUM TOLUENE CONCENTRATION IN THE DISCHARGE WASTE WATER STREAM OF 25 PPM.

$3020 \text{ LBS/HR} \times 25 \text{ PPM} = 0.076 \text{ LBS/HR TOLUENE LOSS}$

SOLIDS:

Aggregate, sand, back dust (calcium carbonate fines) make up roughly 70-80% of the solid feed material. This solid material w/ approx 20% residual solvent from the extraction process is conveyed to the Desolventizer to vaporize and remove the residual solvent. It is common for Soybean material to retain approximate 250-400 ppm of solvent when processed thru similar desolventizing equipment. However, other, higher fiber, higher fines content material like Rapeseed (Canola) retains higher residual solvent (400-600 ppm). We are finding that the shingle aggregate and sand will desolventize somewhat better than porous oil seed cellular structure, but that the shingle fiberglass/cellulose fibers and fine calcium carbonate (back dust) will entrain residual solvent. So we are estimating similar solvent loss w/ the solids out of the desolventizer, to that of higher fines oilseeds – approx 500 ppm residual solvent in the solids discharged from the desolventizer.

ASSUMING 75% SOLIDS

$$200 \text{ T/D} \times 2000 \text{ LBS/T} / 24 \text{ HR/DAY} \times 0.75 = 12500 \text{ LBS/HR}$$

MAXIMUM TOLUENE CONCENTRATION IN THE DISCHARGE SOLIDS OF 500 PPM

$$\text{APPROX } 12500 \text{ LBS/HR} \times 500 \text{ PPM} = 6.25 \text{ LBS/HR TOLUENE LOSS}$$

ASPHALT:

Asphalt content of shingles can range somewhere between approximately 23-27% depending on manufacturer, model/style of shingle, and when the shingle was manufactured.

ASSUME APPROX 25% ASPHALT CONTENT IN THE SOLID FEED MATERIAL.

$$200 \text{ T/D} \times 2000 \text{ LBS/T} \times 0.0417 \text{ HR/D} \times 0.25 = 4170 \text{ LBS/HR}$$

Testing of asphalt stripping using a lab scale version of the proposed Thin Film Evaporator has been conducted w/ varying results based on controlled parameters. The best results, when testing practical operational parameters, indicate that the asphalt stripped in a production plant operation should contain up to 1000-1500 ppm of toluene.

ASSUME A MAXIMUM TOLUENE CONCENTRATION IN THE DISCHARGE ASPHALT STREAM OF 1250 PPM

$$\text{APPROX } 4170 \text{ LBS/HR} \times 1250 \text{ PPM} = 5.21 \text{ LBS/HR TOLUENE LOSS}$$

VAGRANT/FUGATIVE LOSS:

This is a general estimate of possible toluene loss due to leaks throughout the process system (equipment, tanks, vessels, conveyors, piping, pumps, ducting, etc.) and loss from maintenance during operation (liquid and vapor loss due to opening of access panels, replacing filters, etc.). Crown typically estimates an additional 40% of the solvent loss to cover fugitive losses for an average oilseed solvent extraction plant. For this prototype plant, small in scale to oilseed plants, assume 60% for fugitive loss.

$$3.44 \text{ LBS/HR (AIR)} + 0.076 \text{ LBS/HR (WATER)} + 6.25 \text{ LBS/HR (SOLIDS)} + 5.21 \text{ LBS/HR (ASPHALT)} = 14.98 \text{ LBS/HR}$$

$$14.98 \times 0.60 = 8.99 \text{ LBS/HR FUGATIVE TOLUENE LOSS}$$

TOTAL ESTIMATED SOLVENT (TOLUENE) LOSS FOR STANDARD STEADY-STATE OPERATION:

$$3.44 + 0.076 + 6.25 + 5.21 + 8.99 = 23.97 \text{ LBS/HR}$$

$$23.97 \text{ LBS/HR} \times 24 \text{ HRS/D} \times 365 \text{ D} = 209977 \text{ LBS/YR}$$

$$\text{TOLUENE} = 7.26 \text{ LBS/GAL}, 209977 \text{ LBS} / 7.26 = 28922 \text{ GAL/YR}$$

$$28922 \text{ GAL/YR} / (200\text{T/D} \times 365) = 0.396 \text{ GAL/TON (TOLUENE LOSS PER RAW FEED MATERIAL)}$$

OTHER LOSSES:

Losses due to process halts: For various reasons, the plant process or portions of the operations will be halted or momentarily stopped. Loss of feed material, high or low levels in various equipment or tanks, etc. will generate interruptions and halts for process equipment. During these halts, the process will be generating air, waste water and fugitive/vagrant emissions, which are not offset by production. Emission losses will not include solvent loss within product streams (asphalt and solids).

ESTIMATE 18 HRS/WK OF OPERATION HALTS, $18 \text{ HRS/WK} \times 52 \text{ WKS/YR} = 936 \text{ HRS/YR}$

$23.97 \text{ LBS/HR} - 6.25 \text{ LBS/HR (LOSS IN SOLIDS)} - 5.21 \text{ LBS/HR (LOSS IN ASPHALT)}$
 $= 12.51 \text{ LBS/HR LOSSES DURING HALTS.}$

$936 \text{ HRS/YR} \times 12.51 \text{ LBS/HR} = 11709 \text{ LBS/YR ADDITIONAL SOLVENT LOSS}$

Losses due to stoppages: These are maintenance or other emergency stoppages that halt processing and require some maintenance or other action to re-start operations. Can be caused by controls or equipment failures, electrical failures, steam/boiler problems, cooling water flow/temperature, etc. This type of stoppage does not require the process to be emptied or equipment to be purged; generally a utility or equipment failure that can be quickly fixed but creates momentary increase in solvent loss (can be due to leaks, spills, loss of heat to distillation, etc).

ESTIMATE 18 HRS/WK OF STOPPAGES, $18 \text{ HRS/WK} \times 52 \text{ WKS/YR} = 936 \text{ HRS/YR}$

ESTIMATE ADDITIONAL 50% NORMAL SOLVENT LOSS, $23.97 \text{ LBS/HR} \times 1.50 = 35.96 \text{ LBS/HR}$

$936 \text{ HRS/HR} \times 35.96 \text{ LBS/HR} = 33654 \text{ LBS/YR ADDITIONAL SOLVENT LOSS}$

Losses due to Shutdowns: Can be planned or unplanned, due to major required maintenance and cleaning, equipment failure, major utility failure or other operational reason. Because of the flammability of the solvent, any maintenance operation that requires welding, grinding or other electrical tools and equipment (non-Explosion Proof), requires the extraction plant equipment and piping to be purged of liquid and vapor solvent. Much of the liquid solvent can be recovered during the purging process, but much of the solvent vapor with the process equipment, and some liquid solvent in the bottoms of tanks and piping is lost when purged with steam or fan driven air.

The Plant will have approximately 16000 gallons (116160 LBS) of solvent in process during operation (Extractor Liquid levels, Work Tank level, vapor space, distillation system, and associated piping).

Estimate 6 full purge shutdowns per year. Based on vapor space within the equipment and tanks (approx 10000 ft³) and residual liquid solvent in piping, equipment, and tank bottoms (estimate 500 gallons):

$10000 \text{ ft}^3 \text{ toluene vapor} = \text{approx } 2325 \text{ lbs (SG} = 3.1 \times \text{Air)}; 500 \text{ Gal} \times 7.26 \text{ lb/gal} = 3630 \text{ lbs}$

$2325 \text{ LBS} + 3630 \text{ LBS} \times 6 \text{ FULL PURGE/YR} = 35730 \text{ LBS/YR LOSS FROM FULL PURGE SHUTDOWN}$

5955 Lbs per full purge is approximate 5.1% of the in-process solvent.

Estimate 24 partial purge shutdowns per year. Major maintenance or other process shutdown that does not require complete purging of the extraction plant, only local purging of a specific piece of equipment or system. Estimate half the purging loss of a full plant purge, so 2.56% of in-process solvent is lost.

$$116160 \text{ LBS} \times 0.0256 \times 24 \text{ PART PURGE/YR} = 71369 \text{ LBS/YR LOSS FROM PARTIAL PURGE SHUTDOWN}$$

Estimate 36 non-purge shutdowns per year. This requires that equipment be emptied of material, processes shut down, heat/steam turned off. As equipment is emptied and heat is dropped, losses will accelerate. Estimate 1% of in-process solvent is lost during a non-purge shutdown.

$$116160 \text{ LBS} \times 0.01 \times 36 \text{ NON-PURGE SHUTDOWN/YR} = 41818 \text{ LBS/YR LOSS FROM NON-PURGE SHUTDOWN}$$

Losses due to off-spec raw materials: Variations in quality and composition of the incoming shingles will have some effect on the steady-state operation of the plant. Shingles can be new scrap material from manufacturers or up to 30+ year old tear off roofs. The roofing material can include residential shingles, commercial/industrial roofing, tar paper and ice shield in varying percentages. Moisture concentrations of the product entering the process will vary greatly based on ambient temperature and weather conditions. All of this can have some effect on the processing equipment. For example, moisture level will change the steam load on the ground shingle dryer and the water distillation system. Asphalt content will change the steam load on the asphalt distillation system.

Estimate that poor/varying quality of incoming products will adversely affect steady-state operation 36 hrs per week. Estimate that process fluctuations during affected operation can cause an additional 50% emissions increase (of air, water, asphalt and solid streams) during that 36 hrs.

$$3.44 + 0.076 + 6.25 + 5.21 = 14.97$$

$$14.97 \text{ LBS/HR} \times 0.50 = 7.47 \text{ LBS/HR ADDITIONAL SOLVENT LOSS DUE TO INCOMING MATERIAL QUALITY}$$

$$36 \text{ HRS/WK} \times 52 \text{ WEEKS/YR} = 1872 \text{ HRS/YR}$$

$$1872 \text{ HRS/YR} \times 7.47 \text{ LBS/HR} = 13984 \text{ LBS/YR ADDITIONAL SOLVENT LOSS}$$

Losses due to cleaning: Unlike like vegetable oil from oilseed extraction plants, asphalt cannot be cleaned up using water, soaps, caustic or pressure washers. The vast majority of cleaning of equipment, floors, maintenance tools, etc. will need to be done using solvent. Estimate an average of 15 gallons of solvent will be used and lost per day to cleaning activities.

$$15 \text{ GAL/DAY} \times 365 \text{ DAY/YR} \times 7.25 \text{ LBS/GAL} = 39694 \text{ LBS/YR ADDITIONAL SOLVENT LOSS}$$

TOTAL ESTIMATED SOLVENT LOSS:

PRODUCTION RATE: $200 \text{ T/D} \times 365 \text{ D} = 73000 \text{ T/YR} = 146,000,000 \text{ LB/YR}$

209977 LBS/YR STEADY-STATE OPERATION SOLVENT LOSS

11709 LBS/YR ADDITIONAL SOLVENT LOSS (PROCESS HALT)

33654 LBS/YR ADDITIONAL SOLVENT LOSS (PROCESS STOPPAGE)

35730 LBS/YR LOSS FROM FULL PURGE SHUTDOWN

71369 LBS/YR LOSS FROM PARTIAL PURGE SHUTDOWN

41818 LBS/YR LOSS FROM NON-PURGE SHUTDOWN

13984 LBS/YR ADDITIONAL SOLVENT LOSS (VARYING QUALITY MATERIALS)

39694 LBS/YR ADDITIONAL SOLVENT LOSS (CLEANING)

$457935 \text{ LBS/HR} / 7.26 \text{ GAL/LB} = 63076 \text{ GAL.}$

$63076 \text{ GAL} / 73000 \text{ T/YR} = 0.864 \text{ GAL/TON (TOLUENE LOSS PER RAW FEED MATERIAL)}$

JKB – CIW

AP42 SECTION 11.19.2

Table 11.19.2-2 (English Units). EMISSION FACTORS FOR CRUSHED STONE PROCESSING OPERATIONS (lb/Ton)^a

Source ^b	Total Particulate Matter ^{r,s}	EMISSION FACTOR RATING	Total PM-10	EMISSION FACTOR RATING	Total PM-2.5	EMISSION FACTOR RATING
Primary Crushing (SCC 3-05-020-01)	ND		ND ⁿ		ND ⁿ	
Primary Crushing (controlled) (SCC 3-05-020-01)	ND		ND ⁿ		ND ⁿ	
Secondary Crushing (SCC 3-05-020-02)	ND		ND ⁿ		ND ⁿ	
Secondary Crushing (controlled) (SCC 3-05-020-02)	ND		ND ⁿ		ND ⁿ	
Tertiary Crushing (SCC 3-050030-03)	0.0054 ^d	E	0.0024 ^o	C	ND ⁿ	
Tertiary Crushing (controlled) (SCC 3-05-020-03)	0.0012 ^d	E	0.00054 ^p	C	0.00010 ^q	E
Fines Crushing (SCC 3-05-020-05)	0.0390 ^e	E	0.0150 ^e	E	ND	
Fines Crushing (controlled) (SCC 3-05-020-05)	0.0030 ^f	E	0.0012 ^f	E	0.000070 ^q	E
Screening (SCC 3-05-020-02, 03)	0.025 ^c	E	0.0087 ^l	C	ND	
Screening (controlled) (SCC 3-05-020-02, 03)	0.0022 ^d	E	0.00074 ^m	C	0.000050 ^q	E
Fines Screening (SCC 3-05-020-21)	0.30 ^g	E	0.072 ^g	E	ND	
Fines Screening (controlled) (SCC 3-05-020-21)	0.0036 ^g	E	0.0022 ^g	E	ND	
Conveyor Transfer Point (SCC 3-05-020-06)	0.0030 ^h	E	0.00110 ^h	D	ND	
Conveyor Transfer Point (controlled) (SCC 3-05-020-06)	0.00014 ⁱ	E	4.6 x 10 ⁻⁵ⁱ	D	1.3 x 10 ^{-5q}	E
Wet Drilling - Unfragmented Stone (SCC 3-05-020-10)	ND		8.0 x 10 ^{-5j}	E	ND	
Truck Unloading - Fragmented Stone (SCC 3-05-020-31)	ND		1.6 x 10 ^{-5j}	E	ND	
Truck Loading - Conveyor, crushed stone (SCC 3-05-020-32)	ND		0.00010 ^k	E	ND	

a. Emission factors represent uncontrolled emissions unless noted. Emission factors in lb/Ton of material of throughput. SCC = Source Classification Code. ND = No data.

b. Controlled sources (with wet suppression) are those that are part of the processing plant that employs current wet suppression technology similar to the study group. The moisture content of the study group without wet suppression systems operating (uncontrolled) ranged from 0.21 to 1.3 percent, and the same facilities operating wet suppression systems (controlled) ranged from 0.55 to 2.88 percent. Due to carry over of the small amount of moisture required, it has been shown that each source, with the exception of crushers, does not need to employ direct water sprays. Although the moisture content was the only variable measured, other process features may have as much influence on emissions from a given source. Visual observations from each source under normal operating conditions are probably the best indicator of which emission factor is most appropriate. Plants that employ substandard control measures as indicated by visual observations should use the uncontrolled factor with an appropriate control efficiency that best reflects the effectiveness of the controls employed.

c. References 1, 3, 7, and 8

d. References 3, 7, and 8

AP42 SECTION 1.4

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO)
FROM NATURAL GAS COMBUSTION^a

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO _x ^b		CO	
	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS) ^c	280	A	84	B
Uncontrolled (Post-NSPS) ^c	190	A	84	B
Controlled - Low NO _x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (≤100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO _x burners	50	D	84	B
Controlled - Low NO _x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (≤0.3) [No SCC]				
Uncontrolled	94	B	40	B

^a Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/10⁶ scf to kg/10⁶ m³, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from lb/10⁶ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

^b Expressed as NO₂. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_x emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_x emission factor.

^c NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION^a

Pollutant	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating
CO ₂ ^b	120,000	A
Lead	0.0005	D
N ₂ O (Uncontrolled)	2.2	E
N ₂ O (Controlled-low-NO _x burner)	0.64	E
PM (Total) ^c	7.6	D
PM (Condensable) ^c	5.7	D
PM (Filterable) ^c	1.9	B
SO ₂ ^d	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

^a Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from lb/10⁶ scf to kg/10⁶ m³, multiply by 16. To convert from lb/10⁶ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds.

VOC = Volatile Organic Compounds.

^b Based on approximately 100% conversion of fuel carbon to CO₂. CO₂[lb/10⁶ scf] = (3.67) (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO₂, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2x10⁻⁴ lb/10⁶ scf.

^c All PM (total, condensable, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM₁₀, PM_{2.5} or PM₁ emissions. Total PM is the sum of the filterable PM and condensable PM. Condensable PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

^d Based on 100% conversion of fuel sulfur to SO₂.

Assumes sulfur content is natural gas of 2,000 grains/10⁶ scf. The SO₂ emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO₂ emission factor by the ratio of the site-specific sulfur content (grains/10⁶ scf) to 2,000 grains/10⁶ scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM
NATURAL GAS COMBUSTION^a

CAS No.	Pollutant	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene ^{b, c}	2.4E-05	D
56-49-5	3-Methylchloranthrene ^{b, c}	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene ^{b, c}	<1.6E-05	E
83-32-9	Acenaphthene ^{b, c}	<1.8E-06	E
203-96-8	Acenaphthylene ^{b, c}	<1.8E-06	E
120-12-7	Anthracene ^{b, c}	<2.4E-06	E
56-55-3	Benz(a)anthracene ^{b, c}	<1.8E-06	E
71-43-2	Benzene ^b	2.1E-03	B
50-32-8	Benzo(a)pyrene ^{b, c}	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene ^{b, c}	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene ^{b, c}	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene ^{b, c}	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene ^{b, c}	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene ^{b, c}	<1.2E-06	E
25321-22-6	Dichlorobenzene ^b	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene ^{b, c}	3.0E-06	E
86-73-7	Fluorene ^{b, c}	2.8E-06	E
50-00-0	Formaldehyde ^b	7.5E-02	B
110-54-3	Hexane ^b	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene ^{b, c}	<1.8E-06	E
91-20-3	Naphthalene ^b	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene ^{b, c}	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM
NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene ^{b, c}	5.0E-06	E
108-88-3	Toluene ^b	3.4E-03	C

^a Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from lb/10⁶ scf to kg/10⁶ m³, multiply by 16. To convert from lb/10⁶ scf to lb/MMBtu, divide by 1,020. Emission Factors preceded with a less-than symbol are based on method detection limits.

^b Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

^c HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

^d The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION^a

CAS No.	Pollutant	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating
7440-38-2	Arsenic ^b	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium ^b	<1.2E-05	E
7440-43-9	Cadmium ^b	1.1E-03	D
7440-47-3	Chromium ^b	1.4E-03	D
7440-48-4	Cobalt ^b	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese ^b	3.8E-04	D
7439-97-6	Mercury ^b	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel ^b	2.1E-03	C
7782-49-2	Selenium ^b	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

^a Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceded by a less-than symbol are based on method detection limits. To convert from lb/10⁶ scf to kg/10⁶ m³, multiply by 16. To convert from lb/10⁶ scf to lb/MMBtu, divide by 1,020.

^b Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

AP42 SECTION 1.5

Table 1.5-1. EMISSION FACTORS FOR LPG COMBUSTION^a

EMISSION FACTOR RATING: E

Pollutant	Butane Emission Factor (lb/10 ³ gal)		Propane Emission Factor (lb/10 ³ gal)	
	Industrial Boilers ^b (SCC 1-02-010-01)	Commercial Boilers ^c (SCC 1-03-010-01)	Industrial Boilers ^b (SCC 1-02-010-02)	Commercial Boilers ^c (SCC 1-03-010-02)
PM, Filterable ^d	0.2	0.2	0.2	0.2
PM, Condensable	0.6	0.6	0.5	0.5
PM, Total	0.8	0.8	0.7	0.7
SO ₂ ^e	0.09S	0.09S	0.10S	0.10S
NO _x ^f	15	15	13	13
N ₂ O ^g	0.9	0.9	0.9	0.9
CO ₂ ^{h,j}	14,300	14,300	12,500	12,500
CO	8.4	8.4	7.5	7.5
TOC	1.1	1.1	1.0	1.0
CH ₄ ^k	0.2	0.2	0.2	0.2

^a Assumes PM, CO, and TOC emissions are the same, on a heat input basis, as for natural gas combustion. Use heat contents of 91.5 x 10⁶ Btu/10³ gallon for propane, 102 x 10⁶ Btu/10³ gallon for butane, 1020 x 10⁶ Btu/10⁶ scf for methane when calculating an equivalent heat input basis. For example, the equation for converting from methane's emissions factors to propane's emissions factors is as follows: lb pollutant/10³ gallons of propane = (lb pollutant /10⁶ ft³ methane) * (91.5 x 10⁶ Btu/10³ gallons of propane) / (1020 x 10⁶ Btu/10⁶ scf of methane). The NO_x emission factors have been multiplied by a correction factor of 1.5, which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions. To convert from lb/10³ gal to kg/10³ L, multiply by 0.12. SCC = Source Classification Code.

^b Heat input capacities generally between 10 and 100 million Btu/hour.

^c Heat input capacities generally between 0.3 and 10 million Btu/hour.

^d Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. For natural gas, a fuel with similar combustion characteristics, all PM is less than 10 μm in aerodynamic equivalent diameter (PM-10).

^e S equals the sulfur content expressed in gr/100 ft³ gas vapor. For example, if the butane sulfur content is 0.18 gr/100 ft³, the emission factor would be (0.09 x 0.18) = 0.016 lb of SO₂/10³ gal butane burned.

^f Expressed as NO₂.

^g Reference 12.

^h Assuming 99.5% conversion of fuel carbon to CO₂.

^j EMISSION FACTOR RATING = C.

^k Reference 13.

GHG MRR

§ 98.34(a), § 98.164(b), § 98.254(d), and § 98.344(b).

(g) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>.

(1) ISO 3170: Petroleum liquids—Manual sampling—Third Edition 2004-02-01, IBR approved for § 98.164(b).

(2) ISO 3171: Petroleum Liquids—Automatic pipeline sampling—Second Edition 1988-12-01, IBR approved for § 98.164(b).

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987-10-01)—First Edition, IBR approved for § 98.244(b).

(4) ISO/TR 15349-1: 1998, Unalloyed steel—Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998-10-15)—First Edition, IBR approved for § 98.174(b).

(5) ISO/TR 15349-3: 1998, Unalloyed steel—Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998-10-15)—First Edition, IBR approved for § 98.174(b).

(h) The following material is available for purchase from the National Lime

Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243-5463, <http://www.lime.org>.

(1) CO₂ Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision—National Lime Association, incorporation by reference (IBR) approved for § 98.194(c) and § 98.194(e).

(2) [Reserved]

(i) The following material is available for purchase from the National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899-1070, (800) 877-8339, <http://www.nist.gov/index.html>.

(1) Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009), incorporation by reference (IBR) approved for § 98.244(b), § 98.254(h), and § 98.344(a).

(2) [Reserved]

(j) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332-8686, <http://www.tappi.org>.

(1) T650 om-05 Solids Content of Black Liquor, TAPPI, incorporation by reference (IBR) approved for § 98.276(c) and § 98.277(d).

(2) T684 om-06 Gross Heating Value of Black Liquor, TAPPI, incorporation

by reference (IBR) approved for § 98.274(b).

§ 98.8 What are the compliance and enforcement provisions of this part?

Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414). A violation includes but is not limited to failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emissions, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.

§ 98.9 Addresses.

All requests, notifications, and communications to the Administrator pursuant to this part, other than submittal of the annual GHG report, shall be submitted to the following address:

(a) For U.S. mail, Director, Climate Change Division, 1200 Pennsylvania Ave., NW., Mail Code: 6207, Washington, DC 20460.

(b) For package deliveries, Director, Climate Change Division, 1310 L St, NW., Washington, DC 20005.

TABLE A-1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS
[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124-38-9	CO ₂	1
Methane	74-82-8	CH ₄	21
Nitrous oxide	10024-97-2	N ₂ O	310
HFC-23	75-46-7	CHF ₃	11,700
HFC-32	75-10-5	CH ₂ F ₂	650
HFC-41	593-53-3	CH ₃ F	150
HFC-125	354-33-6	C ₂ HF ₅	2,800
HFC-134	359-35-3	C ₂ H ₂ F ₄	1,000
HFC-134a	811-97-2	CH ₂ FCF ₃	1,300
HFC-143	430-66-0	C ₂ H ₃ F ₃	300
HFC-143a	420-46-2	C ₂ H ₃ F ₃	3,800
HFC-152	624-72-6	CH ₂ FCH ₂ F	53
HFC-152a	75-37-6	CH ₃ CHF ₂	140
HFC-161	353-36-6	CH ₃ CH ₂ F	12
HFC-227ea	431-89-0	C ₃ HF ₇	2,900
HFC-236cb	677-56-5	CH ₂ FCF ₂ CF ₃	1,340
HFC-236ea	431-63-0	CHF ₂ CHFCF ₃	1,370
HFC-236fa	690-39-1	C ₃ H ₂ F ₆	6,300
HFC-245ca	679-86-7	C ₃ H ₃ F ₅	560
HFC-245fa	460-73-1	CHF ₂ CH ₂ CF ₃	1,030
HFC-365mfc	406-58-6	CH ₃ CF ₂ CH ₂ CF ₃	794
HFC-43-10mee	138495-42-8	CF ₃ CFHCFHCF ₂ CF ₃	1,300
Sulfur hexafluoride	2551-62-4	SF ₆	23,900
Trifluoromethyl sulphur pentafluoride	373-80-8	SF ₅ CF ₃	17,700
Nitrogen trifluoride	7783-54-2	NF ₃	17,200
PFC-14 (Perfluoromethane)	75-73-0	CF ₄	6,500
PFC-116 (Perfluoroethane)	76-16-4	C ₂ F ₆	9,200
PFC-218 (Perfluoropropane)	76-19-7	C ₃ F ₈	7,000

TABLE A-1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS—Continued
[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Perfluorocyclopropane	931-91-9	C-C ₃ F ₆	17,340
PFC-3-1-10 (Perfluorobutane)	355-25-9	C ₄ F ₁₀	7,000
Perfluorocyclobutane	115-25-3	C-C ₄ F ₈	8,700
PFC-4-1-12 (Perfluoropentane)	678-26-2	C ₅ F ₁₂	7,500
PFC-5-1-14 (Perfluorohexane)	355-42-0	C ₆ F ₁₄	7,400
PFC-9-1-18	306-94-5	C ₁₀ F ₁₈	7,500
HCFE-235da2 (Isoflurane)	26675-46-7	CHF ₂ OCHClCF ₃	350
HFE-43-10pccc (H-Galden 1040x)	E1730133	CHF ₂ OCF ₂ OCF ₂ F ₄ OCHF ₂	1,870
HFE-125	3822-68-2	CHF ₂ OCF ₃	14,900
HFE-134	1691-17-4	CHF ₂ OCHF ₂	6,320
HFE-143a	421-14-7	CH ₃ OCF ₃	756
HFE-227ea	2356-62-9	CF ₃ CHFOCF ₃	1,540
HFE-236ca12 (HG-10)	78522-47-1	CHF ₂ OCF ₂ OCHF ₂	2,800
HFE-236ea2 (Desflurane)	57041-67-5	CHF ₂ OCHF ₂ CF ₃	989
HFE-236fa	20193-67-3	CF ₃ CH ₂ OCF ₃	487
HFE-245cb2	22410-44-2	CH ₃ OCF ₂ CF ₃	708
HFE-245fa1	84011-15-4	CHF ₂ CH ₂ OCF ₃	286
HFE-245fa2	1885-48-9	CHF ₂ OCH ₂ CF ₃	659
HFE-254cb2	425-88-7	CH ₃ OCF ₂ CHF ₂	359
HFE-263fb2	460-43-5	CF ₃ CH ₂ OCH ₃	11
HFE-329mcc2	67490-36-2	CF ₃ CF ₂ OCF ₂ CHF ₂	919
HFE-338mcf2	156053-88-2	CF ₃ CF ₂ OCH ₂ CF ₃	552
HFE-338pcc13 (HG-01)	188690-78-0	CHF ₂ OCF ₂ CF ₂ OCHF ₂	1,500
HFE-347mcc3	28523-86-6	CH ₃ OCF ₂ CF ₂ CF ₃	575
HFE-347mcf2	E1730135	CF ₃ CF ₂ OCH ₂ CHF ₂	374
HFE-347pcf2	406-78-0	CHF ₂ CF ₂ OCH ₂ CF ₃	580
HFE-356mec3	382-34-3	CH ₃ OCF ₂ CHFCF ₃	101
HFE-356pcc3	160620-20-2	CH ₃ OCF ₂ CF ₂ CHF ₂	110
HFE-356pcf2	E1730137	CHF ₂ CH ₂ OCF ₂ CHF ₂	265
HFE-356pcf3	35042-99-0	CHF ₂ OCH ₂ CF ₂ CHF ₂	502
HFE-365mcf3	378-16-5	CF ₃ CF ₂ CH ₂ OCH ₃	11
HFE-374pc2	512-51-6	CH ₃ CH ₂ OCF ₂ CHF ₂	557
HFE-449sl (HFE-7100)	163702-07-6	C ₄ F ₉ OCH ₃	297
Chemical blend	163702-08-7	(CF ₃) ₂ CFCF ₂ OCH ₃	
HFE-569sf2 (HFE-7200)	163702-05-4	C ₄ F ₉ OC ₂ H ₅	59
Chemical blend	163702-06-5	(CF ₃) ₂ CFCF ₂ OC ₂ H ₅	
Sevoflurane	28523-86-6	CH ₂ FOCH(CF ₃) ₂	345
HFE-356mm1	13171-18-1	(CF ₃) ₂ CHOCH ₃	27
HFE-338mmz1	26103-08-2	CHF ₂ OCH(CF ₃) ₂	380
(Octafluorotetramethyl-ene)hydroxymethyl group	NA	X-(CF ₂) ₄ CH(OH)-X	73
HFE-347mmy1	22052-84-2	CH ₃ OCF(CF ₃) ₂	343
Bis(trifluoromethyl)-methanol	920-66-1	(CF ₃) ₂ CHOH	195
2,2,3,3,3-pentafluoropropanol	422-05-9	CF ₃ CF ₂ CH ₂ OH	42
PFPME	NA	CF ₃ OCF(CF ₃)CF ₂ OCF ₂ OCF ₃	10,300

NA = not available.

TABLE A-2 TO SUBPART A OF PART 98—UNITS OF MEASURE CONVERSIONS

To convert from	To	Multiply by
Kilograms (kg)	Pounds (lbs)	2.20462
Pounds (lbs)	Kilograms (kg)	0.45359
Pounds (lbs)	Metric tons	4.53592 × 10 ⁻⁴
Short tons	Pounds (lbs)	2,000
Short tons	Metric tons	0.90718
Metric tons	Short tons	1.10231
Metric tons	Kilograms (kg)	1,000
Cubic meters (m ³)	Cubic feet (ft ³)	35.31467
Cubic feet (ft ³)	Cubic meters (m ³)	0.028317
Gallons (liquid, US)	Liters (l)	3.78541
Liters (l)	Gallons (liquid, US)	0.26417
Barrels of Liquid Fuel (bbl)	Cubic meters (m ³)	0.15891
Cubic meters (m ³)	Barrels of Liquid Fuel (bbl)	6.289
Barrels of Liquid Fuel (bbl)	Gallons (liquid, US)	42
Gallons (liquid, US)	Barrels of Liquid Fuel (bbl)	0.023810
Gallons (liquid, US)	Cubic meters (m ³)	0.0037854
Liters (l)	Cubic meters (m ³)	0.001

in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO₂ mass emissions, in metric tons.

(x) When ASTM methods D7459–08 and D6866–08 are used to determine the biogenic portion of the annual CO₂ emissions from MSW combustion, report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO₂ emissions from MSW combustion is 30 percent, report 0.30).

(B) Annual combined biomass and fossil fuel CO₂ emissions from MSW combustion, in metric tons of CO₂e.

(C) The quantities V_{ff} , V_{total} , and V_{MSW} from § 98.33(e)(4)(ii), if CEMS are used to measure CO₂ emissions.

(D) The annual volume of biogenic CO₂ emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459–08 and D6866–08 are used to determine the biogenic portion of the annual CO₂ emissions from a unit that co-fires biogenic (other than MSW) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO₂ emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO₂ emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO₂ emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel

consumption in units that uses CEMS to quantify CO₂ emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO₂ mass emissions under § 98.33(a)(2)(iii) or to quantify solid fuel usage under § 98.33(c)(3).

(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

§ 98.37 Records that must be retained.

In addition to the requirements of § 98.3(g), you must retain the applicable records specified in §§ 98.34(f) and (g), 98.35(b), and 98.36(e).

§ 98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE C–1 TO SUBPART C OF PART 98—DEFAULT CO₂ EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO ₂ emission factor
Coal and coke	mmBtu/short ton	kg CO ₂ /mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural gas	mmBtu/scf	kg CO ₂ /mmBtu
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum products	mmBtu/gallon	kg CO ₂ /mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97

TABLE C-1 TO SUBPART C OF PART 98—DEFAULT CO₂ EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default high heat value	Default CO ₂ emission factor
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil fuel-derived fuels (solid)	mmBtu/short ton	kg CO ₂ /mmBtu
Municipal Solid Waste ¹	9.95	90.7
Tires	26.87	85.97
Fossil fuel-derived fuels (gaseous)	mmBtu/scf	kg CO ₂ /mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass fuels—solid	mmBtu/short ton	kg CO ₂ /mmBtu
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO ₂ /mmBtu
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO ₂ /mmBtu
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

¹ Allowed only for units that do not generate steam and use Tier 1.

TABLE C-2 TO SUBPART C OF PART 98—DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH ₄ emission factor (kg CH ₄ /mmBtu)	Default N ₂ O emission factor (kg N ₂ O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-3}
Natural Gas	1.0×10^{-3}	1.0×10^{-4}
Petroleum (All fuel types in Table C-1)	3.0×10^{-3}	6.0×10^{-4}
Municipal Solid Waste	3.2×10^{-2}	4.2×10^{-3}
Tires	3.2×10^{-2}	4.2×10^{-3}
Blast Furnace Gas	2.2×10^{-5}	1.0×10^{-4}
Coke Oven Gas	4.8×10^{-4}	1.0×10^{-4}
Biomass Fuels—Solid (All fuel types in Table C-1)	3.2×10^{-2}	4.2×10^{-3}
Biogas	3.2×10^{-3}	6.3×10^{-4}
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-3}	1.1×10^{-4}

Note: Those employing this table are assumed to fall under the IPCC definitions of the “Energy Industry” or “Manufacturing Industries and Construction”. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC “Energy Industry” category may employ a value of 1g of CH₄/MMBtu.

¹ Allowed only for units that do not generate steam and use Tier 1.

TABLE C-2 TO SUBPART C—DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH ₄ emission factor (kg CH ₄ /mmBtu)	Default N ₂ O emission factor (kg N ₂ O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-2}	1.6×10^{-3}
Natural Gas	1.0×10^{-3}	1.0×10^{-4}

TABLE C-2 TO SUBPART C—DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default CH ₄ emission factor (kg CH ₄ /mmBtu)	Default N ₂ O emission factor (kg N ₂ O/mmBtu)
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C-1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the “Energy Industry” or “Manufacturing Industries and Construction”. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC “Energy Industry” category may employ a value of 1 g of CH₄/MMBtu.

Subpart D—Electricity Generation

§ 98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in § 98.6.

§ 98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of § 98.2(a)(1).

§ 98.42 GHGs to report.

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR part 75, you must report under this subpart the annual mass emissions of CO₂, N₂O, and CH₄ by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O by following the requirements of subpart C of this part.

§ 98.43 Calculating GHG emissions.

Continue to monitor and report CO₂ mass emissions as required under § 75.13 or section 2.3 of appendix G to 40 CFR part 75, and § 75.64. Calculate CO₂, CH₄, and N₂O emissions as follows:

(a) Convert the cumulative annual CO₂ mass emissions reported in the fourth quarter electronic data report required under § 75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(b) Calculate and report annual CH₄ and N₂O mass emissions under this subpart by following the applicable method specified in § 98.33(c).

§ 98.44 Monitoring and QA/QC requirements.

Follow the applicable quality assurance procedures for CO₂ emissions in appendices B, D, and G to 40 CFR part 75.

§ 98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§ 98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in § 98.36(b) and, if applicable, § 98.36(c)(2) or (c)(3).

§ 98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§ 98.3(g) and 98.37.

§ 98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart E—Adipic Acid Production

§ 98.50 Definition of source category.

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ 98.51 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an adipic acid production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.52 GHGs to report.

(a) You must report N₂O process emissions at the facility level.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C.

§ 98.53 Calculating GHG emissions.

(a) You must determine annual N₂O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Administrator approval for an alternative method of determining N₂O emissions according to paragraphs (a)(2)(i) and (a)(2)(ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N₂O emissions factor for the current reporting period using the procedures specified in paragraphs (b) through (h) of this section.

(b) You must conduct an annual performance test according to

AP42 SECTION 3.3

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES^a

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01)		Diesel Fuel (SCC 2-02-001-02, 2-03-001-01)		EMISSION FACTOR RATING
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	
NO _x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03 ^d	0.99 ^d	6.68 E-03	0.95	D
SO _x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10 ^b	7.21 E-04	0.10	2.20 E-03	0.31	D
CO ₂ ^c	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

^a References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.


^b PM-10 = particulate matter less than or equal to 10 µm aerodynamic diameter. All particulate is assumed to be ≤ 1 µm in size.

^c Assumes 99% conversion of carbon in fuel to CO₂ with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

^d Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION
FACTORS FOR UNCONTROLLED DIESEL ENGINES^a

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene ^b	9.33 E-04
Toluene ^b	4.09 E-04
Xylenes ^b	2.85 E-04
Propylene 	2.58 E-03
1,3-Butadiene ^{b,c}	<3.91 E-05
Formaldehyde ^b	1.18 E-03
Acetaldehyde ^b	7.67 E-04
Acrolein ^b	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene ^b	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,i)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

^a Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.

^b Hazardous air pollutant listed in the *Clean Air Act*.

^c Based on data from 1 engine.