SWCAA
Southwest Clean Air Agency

TECHNICAL SUPPORT DOCUMENT

Air Discharge Permit ADP 16-3204
ADP Application CO-964

Northwest Innovation Works Kalama
SWCAA ID - 2455

Final Issued: June 7, 2017

Prepared By: Wess Safford
Air Quality Engineer
Southwest Clean Air Agency

TABLE OF CONTENTS

Abbreviations

acfm	actual cubic feet per minute
ADP	Air Discharge Permit
AP-42	Compilation of Emission Factors, AP-42, Fifth Edition, Volume 1, Stationary Point and Area Sources – published by the US Environmental Protection Agency
BACT	Best available control technology
Btu	British thermal unit
CEMS	Continuous emission monitoring system
CERMS	Continuous emission rate monitoring system
CAS #	Chemical Abstracts Service registry number
cfm	Cubic feet per minute
CFR	Code of Federal Regulations
CO	Carbon monoxide
dscfm	Dry standard cubic feet per minute
EPA	U.S. Environmental Protection Agency
ft^2	Square feet
g/hp-hr	Grams per horsepower hour
gr/dscf	Grains per dry standard cubic foot (68 °F, 1 atmosphere)
HAP	Hazardous air pollutant listed pursuant to Section 112 of the Federal Clean Air Act
$lb/10^3$ gal	Pounds per thousand gallons
$lb/10^6$ scf	Pounds per million standard cubic feet
lb/hp-hr	Pounds per horsepower hour
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
lb/ton	Pounds per ton
lb/yr	Pounds per year
MMBtu/hr	Millions of British thermal units per hour
MSDS	Material Safety Data Sheet
NO_x	Nitrogen oxides
oz/yd^2	Once per square yard
PM	Total particulate matter (includes both filterable and condensable particulate matter as measured by EPA Methods 5 and 202)
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (includes both filterable and condensable particulate matter as measured by EPA Methods 5 and 202)
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers (includes both filterable and condensable particulate matter as measured by EPA Methods 5 and 202)
ppm	Parts per million
ppmv	Parts per million by volume
ppmvd	Parts per million by volume, dry
psig	Pounds per square inch, gauge
RACT	Reasonably Available Control Technology
RCW	Revised Code of Washington
SQER	Small Quantity Emission Rate listed in WAC 173-460
SO_2	Sulfur dioxide
SWCAA	Southwest Clean Air Agency
TAP	Toxic air pollutant pursuant to Chapter 173-460 WAC
T-BACT	Best Available Control Technology for toxic air pollutants
tph	Tons per hour
tpy	Tons per year
VOC	Volatile organic compound
WAC	Washington Administrative Code

1. FACILITY IDENTIFICATION

Applicant Name:	Northwest Innovation Works Kalama, LLC
Applicant Address:	380 W. Marine Drive, Kalama, WA 98625
Facility Name:	Northwest Innovation Works Kalama
Facility Address:	222 Tradewinds Road, Kalama, WA 98625
Contact person:	Kurt Humphrey, Environmental Manager
SWCAA Identification:	2455
Primary Process:	Industrial Organic Chemicals / Organic Chemical Manufacturing
SIC/NAICS Code:	2869 / 325199
Facility Classification:	Minor

2. FACILITY DESCRIPTION

Northwest Innovations Works Kalama (NWIWK) proposes to construct and operate a methanol production facility on approximately 90 acres at the Port of Kalama's Northport site. The proposed facility is referred to as the Kalama Manufacturing and Marine Export Facility (KMMEF).

As proposed, KMMEF will have the capacity to produce up to 10,000 metric tons of AA grade methanol per day, and will be configured with two production lines, each with a daily production capacity of 5,000 metric tons. Annual methanol production capacity will be approximately 3.6 million metric tons per year (mtpy). Methanol will be manufactured by removing impurities from natural gas, creating synthesis gas ("syngas") from the purified feedstock gas, and then converting the syngas into liquid methanol. Natural gas feedstock for the facility will be provided via pipeline by Northwest Pipeline GP. Finished methanol will be stored on site prior to shipment to global markets via marine vessel. A new dock will be constructed in support of shipping operations.

3. CURRENT PERMITTING ACTION

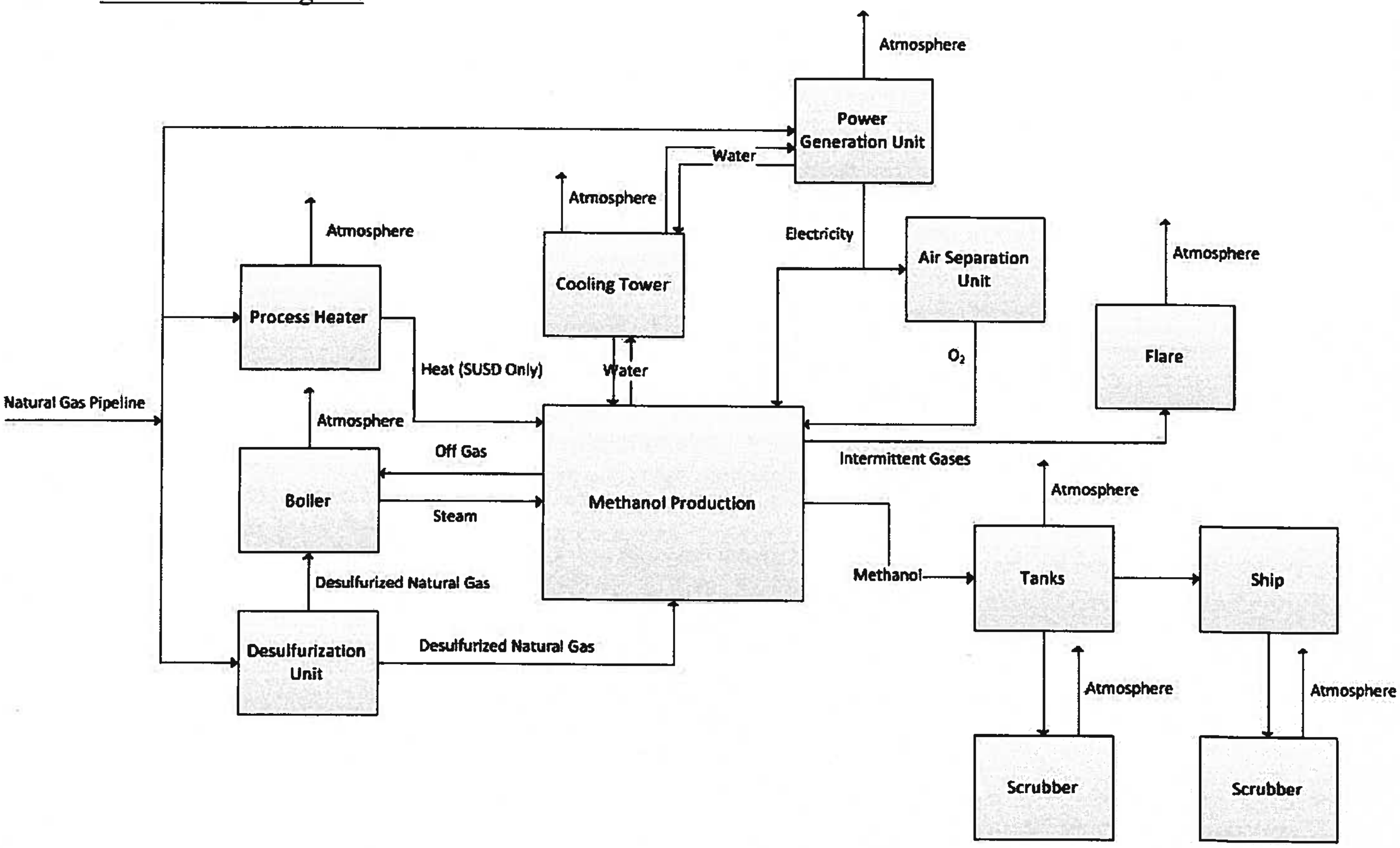
This permitting action is in response to Air Discharge Permit application number CO-964 (ADP Application CO-964) dated February 24, 2016. ADP Application CO-964 requesting approval for multiple emission units that will be installed in support of methanol manufacturing operations. The affected emission units are as follows:

- Three gas-fired steam boilers (530 MMBtu/hr each)
- Two combined cycle combustion turbines (~453 MMBtu/hr each)
- Two once through steam generators equipped with duct burners (~105 MMBtu/hr each)
- Two process heaters (~74.5 MMBtu/hr each)
- One process gas flare
- Two syngas conversion units
- Two methanol distillation units
- Fourteen bulk methanol storage tanks
- Bulk liquid shiploading equipment
- Three bulk ammonia storage tanks
- One 12-cell mechanical draft cooling tower
- Two diesel engine powered emergency generators (4,628 hp each)
- One diesel engine powered fire pump (1,600 hp)

The current permitting action provides approval for a new methanol manufacturing facility as proposed in ADP Application CO-964.

4. PROCESS DESCRIPTION

4.a Process Flow Diagram.



4.b Process Overview. Methanol, also known as methyl alcohol or wood alcohol, is the simplest of all alcohols with the chemical formula CH_3OH. It is biodegradable and noncarcinogenic. Methanol can be used as a fuel, but is more commonly used as an essential ingredient in chemical and manufacturing processes for products, including paint, particle board, plastics, carpets, pharmaceuticals, laminated lumber, and windshield wiper fluid. Production of methanol from natural gas is an established technology. Natural gas is combined with steam and heat to produce syngas, which is composed of carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2). The syngas is then exposed to a catalyst, resulting in a crude methanol liquid mixture. Crude methanol is distilled to yield a mixture composed of 99.9 percent pure methanol and 0.1 percent water.

Air pollutant emissions attributable to the project will be generated by commonplace industrial equipment such as boilers, process heaters, combustion turbines, and cooling towers. There will be no direct emissions from the natural gas reformers (i.e., the GHR and the ATR), the methanol synthesis and distillation process equipment, the natural gas desulfurization system, or the onsite air separation units (ASU).

4.c Natural Gas Desulfurization. Natural gas arriving at the Facility by pipeline will be treated to remove sulfur compounds. Desulfurized natural gas will be then compressed, and saturated with process water.

4.d Synthetic Gas Production. Synthetic gas (syngas) will be produced from natural gas using a two stage reforming process. The first stage partially reforms water-rich natural gas using heat and steam. The second stage completes the reforming process with oxygen using an auto-thermal reformer (ATR). The reforming process produces a syngas with the optimum composition for methanol production. The Facility will use Ultra-Low Emission (ULE) reforming technology, which employs a syngas-heated reformer (GHR). Rather than combusting natural gas to provide heat for the primary reforming step, the hot syngas from the secondary reforming step (i.e., the ATR) flows through the shell side of the primary reformer (i.e., the GHR), where heat in transferred to the feedstock on the tube side. After leaving the shell-side of the GHR, the syngas is passed through a series of heat exchangers that recover waste heat to provide energy for the methanol synthesis and distillation processes.

4.e Crude Methanol Production. Syngas produced in the reforming process will be sent to converters where it is converted to crude methanol. Not all of the syngas is converted to methanol in the converters. Outlet gas from the converters contains a mixture of methanol, unreacted syngas, and by-products. Outlet gas flows through a series of coolers designed to condense methanol product and recover/reuse waste process heat. Condensed crude methanol is sent to storage, and then purified via distillation. Recovered syngas is compressed and recycled back to the converters to enhance methanol production. Gaseous by-products that cannot be recycled back to the converters are vented to the process boilers and combusted.

4.f Crude Methanol Storage. Condensed crude methanol will be stored in vertical bulk storage tanks prior to distillation. While in use, a "nitrogen blanket" will be maintained in the headspace of each storage tank. Displaced vapors from tank operation will be captured with a closed ventilation system and routed to a wet scrubber.

4.g Crude Methanol Distillation. Crude methanol from the synthesis process will be sent to distillation units where it is purified. Water and several other hydrocarbon by-products are synthesized at the same time as methanol, and must be removed from the crude methanol mixture. Water and gaseous by-products are separated from the methanol using a separation vessel and a series of three distillation columns. Recovered water is reused in the production process. Gaseous by-products are vented to the process boilers and combusted.

4.h Finished Methanol Storage. Refined methanol will be stored onsite in vertical bulk storage tanks prior to shipment. While in use, a "nitrogen blanket" will be maintained in the headspace of each storage tank. Headspace vapors displaced during tank operation will be captured with a closed ventilation system and routed to a wet scrubber.

4.i Ship Loading - Methanol. Finished methanol will be shipped from the facility via marine vessel using a dedicated ship loading berth. Headspace vapors displaced during ship loading of methanol will be captured with a closed ventilation system and routed to a wet scrubber.

4.j Process Boilers. Three natural gas fired boilers will be used to provide process steam to the first stage of the natural gas reforming process. Two boilers will operate at any one time with one unit held in reserve. The boilers will fire on pipeline natural gas at initial process startup and a combination of desulfurized natural gas and gaseous waste streams from the syngas converters and distillation units during regular operation. Emissions of NO_X and CO will be minimized through the use of selective catalytic reduction (SCR) and oxidation catalyst systems.

4.k Process Heaters. Two natural gas fired heaters will be used to heat the natural gas reforming process during startup and shutdown. The reforming process is largely self-heating during normal operation so the heaters are only needed during startup and shutdown. The process heaters will be fired exclusively on pipeline natural gas.

4.l Bulk Ammonia Storage. The facility's process boilers and power generation units will be equipped with selective catalytic reduction (SCR) systems to control NO_X emissions. The SCR systems use aqueous ammonia as a reagent. The aqueous ammonia will be stored onsite in vertical bulk storage tanks prior to use.

4.m Primary Power Generation. The facility's primary electrical load is larger than the capacity of the local electric utility. Approximately half of the facility's electrical load will be provided by an onsite power generation unit (PGU). The PGU will consist of two combined cycle, combustion turbines. Each combustion turbine drives an electric generator. Steam from the steam generators is combined to drive a separate steam turbine/electric generator. The steam generators have a once through design (OTSG), and are equipped with duct burners. All units are fired exclusively on pipeline natural gas. Emissions of NO_X and CO will be minimized through the use of selective catalytic reduction (SCR) and oxidation catalyst systems.

4.n Emergency Power Generation. Two diesel engine powered generators will be used to provide emergency electrical power to essential systems at the facility in the event of a primary power failure.

4.o Emergency Fire Pump. One diesel engine driven fire pump will be used to power fire suppression systems at the facility in the event of a primary power failure.

5. EQUIPMENT/ACTIVITY IDENTIFICATION

5.a Power Generation Unit #1. This unit is part provides primary electrical power for facility operations. The unit consists of a combustion turbine (CT) in sequence with a dedicated once through steam generator (OTSG). The turbine directly drives an electric generator with a nominal output of 45 MW. Steam generated in the steam generator is combined with steam from Steam Generator #2 to power a separate electric generator with a nominal output of 31 MW. This unit will be equipped with a selective catalytic reduction (SCR) system capable of maintaining NO_X exhaust emissions at, or below, 2.5 ppmv @ 15% O_2 (3-hr avg). This unit will be equipped with an oxidation catalyst system capable of maintaining CO exhaust emissions at, or below, 4.0 ppmv @ 15% O_2 (3-hr avg) and VOC exhaust emissions at, or below, 3.0 ppmv @ 15% O_2 (3-hr avg). Exhaust gases from the combustion turbine/OTSG will be discharged vertically through a 12.6' diameter exhaust stack at 95' above ground level.

CT #1. General Electric model LM6000-PF natural gas fired combustion turbine equipped with low-NO_X combustors and evaporative inlet cooling. Maximum rated heat input for the turbine is identified as ~453 MMBtu/hr.

OTSG #1. Site built heat recovery steam generator used to generate steam from combustion turbine exhaust waste heat. The steam generator has a once through configuration, and is equipped with natural gas fired duct burners rated at ~105 MMBtu/hr to supply supplemental heat. Duct burners are fired as necessary to provide the desired facility output.

5.b Power Generation Unit #2. This unit is part provides primary electrical power for facility operations. The unit consists of a combustion turbine (CT) in sequence with a dedicated once through steam generator (OTSG). The turbine directly drives an electric generator with a nominal output of 45 MW. Steam generated in the steam generator is combined with steam from Steam Generator #1 to power a separate electric generator with a nominal output of 31 MW. This unit will be equipped with a selective catalytic reduction (SCR) system capable of maintaining NO_X exhaust emissions at, or below, 2.5 ppmv @ 15% O_2 (3-hr avg). This unit will be equipped with an oxidation catalyst system capable of maintaining CO exhaust emissions at, or below, 4.0 ppmv @ 15% O_2 (3-hr avg) and VOC exhaust emissions at, or below, 3.0 ppmv @ 15% O_2 (3-hr avg). Exhaust gases from the combustion turbine/OTSG will be discharged vertically through a 12.6' diameter exhaust stack at 95' above ground level.

CT #2. General Electric model LM6000-PF natural gas fired combustion turbine equipped with low-NO_X combustors and evaporative inlet cooling. Maximum rated heat input for the turbine is identified as ~453 MMBtu/hr.

OTSG #2. Site built heat recovery steam generator used to generate steam from combustion turbine exhaust waste heat. The steam generator has a once through configuration, and is equipped with natural gas fired duct burners rated at ~105 MMBtu/hr to supply supplemental heat. Duct burners are fired as necessary to provide the desired facility output.

5.c Process Boiler #1. This unit provides process steam for the primary stage of the natural gas reforming process. The unit will be equipped with a low NO_X burner assembly and add-on emission controls for NO_X, CO and VOC.

Make / Model:	TBD / TBD
Rated Heat Input:	530 MMBtu/hr
Fuel:	Natural Gas / Process Gas
Emissions:	4.0 ppmv NO_X @ 3% O_2 (SCR)
	5.0 ppmv CO @ 3% O_2 (oxidation catalyst)
	6.0 ppmv VOC @ 3% O_2 (oxidation catalyst)
Exhaust:	98" dia vertical stack at 50' above ground level.

5.d Process Boiler #2. This unit provides process steam for the primary stage of the natural gas reforming process. The unit will be equipped with a low NO_X burner assembly and add-on emission controls for NO_X, CO and VOC.

Make / Model:	TBD / TBD
Rated Heat Input:	530 MMBtu/hr
Fuel:	Natural Gas / Process Gas
Emissions:	4.0 ppmv NO_X @ 3% O_2 (SCR)
	5.0 ppmv CO @ 3% O_2 (oxidation catalyst)
	6.0 ppmv VOC @ 3% O_2 (oxidation catalyst)
Exhaust:	98" dia vertical stack at 50' above ground level.

5.e Process Boiler #3. This unit provides process steam for the primary stage of the natural gas reforming process. The unit will be equipped with a low NO_X burner assembly and add-on emission controls for NO_X, CO and VOC.

Make / Model:	TBD / TBD
Rated Heat Input:	530 MMBtu/hr
Fuel:	Natural Gas / Process Gas
Emissions:	4.0 ppmv NO_X @ 3% O_2 (SCR)
	5.0 ppmv CO @ 3% O_2 (oxidation catalyst)
	6.0 ppmv VOC @ 3% O_2 (oxidation catalyst)
Exhaust:	98" dia vertical stack at 50' above ground level.

5.f Process Heater #1. This unit provides process heat to the gas heated reformer (GHR) on the associated production line during startup and shutdown. Operation is limited because process heat for the GHR unit is provided via recovery heat from the auto-thermal reformer (ATR) once normal operating conditions are achieved. The unit will be equipped with a low NO_X burner assembly to control emissions of NO_X.

Make / Model:	TBD / TBD
Rated Heat Input:	74.5 MMBtu/hr
Fuel:	Natural gas
Emissions:	0.032 lb/MMBtu NO_X (FGR)
	0.0325 lb/MMBtu CO (GCP)
	0.0052 lb/MMBtu VOC (GCP)
Exhaust:	38.5" dia vertical stack at 50' above ground level.

5.g Process Heater #2. This unit provides process heat to the GHR unit on the associated production line during startup and shutdown. Operation is limited because process heat for the GHR unit is provided via recovery heat from the ATR once normal operating conditions are achieved. The unit will be equipped with a low NO_X burner assembly to control emissions of NO_X.

Make / Model:	TBD / TBD
Rated Heat Input:	74.5 MMBtu/hr
Fuel:	Natural gas
Emissions:	0.032 lb/MMBtu NO_X (FGR)
	0.0325 lb/MMBtu CO (GCP)
	0.0052 lb/MMBtu VOC (GCP)
Exhaust:	38.5" dia vertical stack at 50' above ground level.

5.h Process Flare. This unit is used to dispose of combustible gas streams from the methanol production lines, The unit operates primarily during routine startup/shutdown and minor process upsets, but is designed to handle vented gas streams during emergency shutdowns. The unit is designed to maintain a destruction efficiency of 99%.

Make / Model:	TBD / TBD
Flare Design:	Elevated, open flare
Rated Heat Input:	6,150 MMBtu/hr
Supplemental Fuel:	Natural Gas
Pilot Heat Input:	0.333 MMBtu/hr
Exhaust:	24" dia vertical stack at 215' above ground level.

5.i Syngas Converters. These units are comprised of a collection of methanol synthesis equipment dedicated to each production line. Liquid output from the units is sent to storage tanks. Gaseous output (unreacted syngas and by-products) is compressed and recycled back to the conversion process (syngas) or vented to the process boilers and combusted (by-products).

5.j Crude Methanol Distillation Units. These units are comprised of a collection of separation equipment dedicated to each production line. The units separate water and by-products from crude methanol using separation vessels and distillation columns. Refined methanol and water are sent to storage tanks. Gaseous by-products are vented to the process boilers and combusted.

5.k Methanol Storage - Crude Methanol Tanks. Two vertical bulk storage tanks are used to store bulk crude methanol produced in the primary conversion process. Crude methanol in these tanks is pumped to the distillation unit for refining. Each tank is equipped with a closed ventilation system that captures displaced headspace vapors and routes the stream to the storage tank wet scrubber. Tank headspaces will be filled with nitrogen during active operation to minimize the risk of fire. Individual tanks are described as follows:

Tank Type:	Fixed External Roof
Shell Dimensions:	82' diameter / 58' high
Tank Capacity:	2,275,000 gallons (nominal)

5.l Methanol Storage - Shift Tanks. Four vertical bulk storage tanks are used to store distilled methanol produced in the distillation unit. Distilled methanol is stored in these tanks while purity and quality control tests are performed. Approved product is pumped to the finished methanol storage tanks. Each tank is equipped with a closed ventilation system that captures displaced headspace vapors and routes the stream to the storage tank wet scrubber. Tank headspaces will be filled with nitrogen during active operation to minimize the risk of fire. Individual tanks are described as follows:

Tank Type:	Fixed External Roof / Floating Internal Roof
Tank Seals:	Mechanical Shoe (Primary) / Rim-mounted (Secondary)
Shell Dimensions:	60' diameter / 50' high
Tank Capacity:	1,000,000 gallons (nominal)

5.m Methanol Storage - Finished Methanol Tanks. Eight vertical bulk storage tanks are used to store finished methanol prior to shipment via marine vessel. Each tank is equipped with a closed ventilation system that captures displaced headspace vapors and routes the stream to the storage tank wet scrubber. Tank headspaces will be filled with nitrogen during active operation to minimize the risk of fire. Individual tanks are described as follows:

Tank Type:	Fixed External Roof / Floating Internal Roof
Tank Seals:	Mechanical Shoe (Primary) / Rim-mounted (Secondary)
Shell Dimensions:	143' diameter / 82' high
Tank Capacity:	9,400,000 gallons (nominal)

Methanol Storage Tank Scrubber. This unit controls displaced headspace vapors from the methanol storage tanks. Vapors collected by the tank ventilation systems will be vented to a wet scrubber using water as a scrubbing liquor. Manufacturer's information specifies a minimum capture efficiency of 99% for methanol vapors. Maximum rated capacity is 21,200 cfm. Scrubber exhaust is discharged vertically through a 3' diameter exhaust stack at a height of 30' above ground level.

5.o Marine Vessel Loading Operations. A marine loading rack will be used to transfer methanol from storage to marine tank vessels (ships/barges). The loading rack will be configured with submerged fill. Displaced headspace vapors from vessel tanks will be captured by a vapor recovery system and vented to a dedicated wet scrubber.

Marine Vessel Loading Scrubber. Headspace vapors captured by the vapor recovery system will be vented to a wet scrubber using water as a scrubbing liquor. Manufacturer's information specifies a minimum capture efficiency of 99% for methanol vapors. Maximum rated capacity is 21,200 cfm. Scrubber exhaust is discharged vertically through a 3' diameter exhaust stack at a height of 35' above ground level.

5.p Ammonia Storage - SCR Tanks. Three vertical bulk storage tanks are used to store aqueous ammonia prior to its use in the SCR systems associated with the process boilers and power generation units.

Tank Type:	Vertical
Vent Control:	P/V valve (0.03 psi, -0.03 psi)
Shell Dimensions:	7.5' diameter / 30' length
Tank Capacity:	9,000 gallons (nominal)

5.q Cooling Tower. One mechanically-induced-draft, multi-cell cooling tower with a design water circulation rate of 260,400 gal/min. The cooling tower is equipped with drift eliminators to minimize PM emissions. The drift eliminator design is guaranteed to limit drift to a maximum rate of 0.0005%.

5.r Diesel Engine - Emergency Generator #1. This unit provides electrical power to critical systems at the facility in the event of a loss in primary/utility electrical power.

Engine Make / Model:	TBD (Caterpillar C175-20 or equivalent)
Engine Power Rating:	4,628 bhp
Engine Fuel Consumption:	275 gal/hr
Engine Mfg Date / Certification:	2016 (EPA Tier 4)
Generator Power Rating:	4,000 kW
Exhaust:	24" dia vertical stack at ~27' above ground level.

5.s Diesel Engine - Emergency Generator #2. This unit provides electrical power to critical systems at the facility in the event of a loss in primary/utility electrical power.

Engine Make / Model:	TBD (Caterpillar C175-20 or equivalent)
Engine Power Rating:	4,628 bhp
Engine Fuel Consumption:	275 gal/hr
Engine Mfg Date / Certification:	2016 (EPA Tier 4)
Generator Power Rating:	4,000 kW
Exhaust:	24" dia vertical stack at ~27' above ground level.

5.t Diesel Engine - Emergency Fire Pump. This unit provides pressurized water to fire suppression systems at the facility in the event of a loss in primary/utility electrical power.

Engine Make / Model:	TBD (Clarke JW6H-UFADF0 or equivalent)
Engine Power Rating:	1,600 bhp
Engine Fuel Consumption:	84.1 gal/hr
Engine Mfg Date / Certification:	2016 (EPA Tier 2)
Exhaust:	14" dia vertical stack at 36' above ground level.

5.u Insignificant Emission Units. The following pieces of facility equipment have been determined to have insignificant emissions, and are not registered as emission units:

ZLD Process Unit. This facility will use a zero liquids discharge (ZLD) system to dispose of multiple wastewater streams. The ZLD system has a small aerator vent that discharges to atmosphere. Wastewater streams sent through the aerator contain no hydrocarbons and minimal levels of dissolved solids so potential emissions of VOC and PM are negligible.

5.v Equipment/Activity Summary.

ID No.	Generating Equipment/Activity	# of Units	Control Measure/Equipment	# of Units
1	Power Generation Unit #1 (LM6000-PF w/duct burner - 558 MMBtu/Hr)	1	Low Sulfur Fuel, Low NO_X Burner, NO_X/CO/VOC Catalyst Systems	1
2	Power Generation Unit #2 (LM6000-PF w/duct burner - 558 MMBtu/Hr)	1	Low Sulfur Fuel, Low NO_X Burner, NO_X/CO/VOC Catalyst Systems	1
3	Process Boiler #1 (530 MMBtu/hr)	1	Low Sulfur Fuel, Low NO_X Burner, NO_X/CO/VOC Catalyst Systems	1

ID No.	Generating Equipment/Activity	# of Units	Control Measure/Equipment	# of Units
4	Process Boiler #2 (530 MMBtu/hr)	1	Low Sulfur Fuel, Low NO_X Burner, NO_X/CO/VOC Catalyst Systems	1
5	Process Boiler #3 (530 MMBtu/hr)	1	Low Sulfur Fuel, Low NO_X Burner, NO_X/CO/VOC Catalyst Systems	1
6	Process Heater #1 (74.5 MMBtu/hr)	1	Low Sulfur Fuel, Low NO_X Burner	1
7	Process Heater #2 (74.5 MMBtu/hr)	1	Low Sulfur Fuel, Low NO_X Burner	1
8	Process Flare (6,150 MMBtu/hr)	1	High Temperature Combustion	N/A
9	Syngas Converter - Line #1	1	Process Enclosure, High Temperature Combustion	N/A
10	Syngas Converter - Line #2	1	Process Enclosure, High Temperature Combustion	N/A
11	Crude Methanol Distillation Unit - Line #1	1	Process Enclosure, High Temperature Combustion	N/A
12	Crude Methanol Distillation Unit - Line #2	1	Process Enclosure, High Temperature Combustion	N/A
13	Methanol Storage - Crude Methanol Tank #1 (2,275,000 gal)	1	Vapor Capture, Wet Scrubber	1
14	Methanol Storage - Crude Methanol Tank #2 (2,275,000 gal)	1	Vapor Capture, Wet Scrubber	1
15	Methanol Storage - Shift Tank #1 (1,000,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
16	Methanol Storage - Shift Tank #2 (1,000,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
17	Methanol Storage - Shift Tank #3 (1,000,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
18	Methanol Storage - Shift Tank #4 (1,000,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
19	Methanol Storage - Finished Methanol Tank #1 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
20	Methanol Storage - Finished Methanol Tank #2 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
21	Methanol Storage - Finished Methanol Tank #3 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
22	Methanol Storage - Finished Methanol Tank #4 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
23	Methanol Storage - Finished Methanol Tank #5 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1

ID No.	Generating Equipment/Activity	# of Units	Control Measure/Equipment	# of Units
24	Methanol Storage - Finished Methanol Tank #6 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
25	Methanol Storage - Finished Methanol Tank #7 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
26	Methanol Storage - Finished Methanol Tank #8 (9,400,000 gal)	1	Internal Floating Roof, Vapor Capture, Wet Scrubber	1
27	Marine Vessel Loading Operations	1	Submerged Fill, Vapor Capture, Wet Scrubber	1
28	Fugitive Component Emissions	--	Process Enclosure, LDAR Program	--
29	Ammonia Storage - SCR Tank #1 (9,000 gal)	1	P/V Valve	N/A
30	Ammonia Storage - SCR Tank #2 (9,000 gal)	1	P/V Valve	N/A
31	Ammonia Storage - SCR Tank #3 (9,000 gal)	1	P/V Valve	N/A
32	Cooling Tower (260,400 gal/min)	1	Drift Eliminators	N/A
33	Diesel Engine - Emergency Generator #1 (4,628 bhp)	1	Ultra-low Sulfur Diesel EPA Tier Certification	N/A
34	Diesel Engine - Emergency Generator #2 (4,628 bhp)	1	Ultra-low Sulfur Diesel EPA Tier Certification	N/A
35	Diesel Engine - Fire Pump #1 (1,600 bhp)	1	Ultra-low Sulfur Diesel EPA Tier Certification	N/A

6. EMISSIONS DETERMINATION

Emissions to the ambient atmosphere from the equipment/operations proposed in ADP Application CO-964 consist of nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM) sulfur dioxide (SO_2), toxic air pollutants (TAPs), and hazardous air pollutants (HAPs).

6.a Process Boilers. Potential emissions from operation of the process boilers are calculated from specified heat input rates, proposed hours of operation, and applicable emission factors. Annual emissions from boiler operation will be calculated based on actual fuel consumption and applicable emission factors.

Heat input rates for each boiler are specified as 530 MMBtu/hr (full load - normal operation and process startup), 133 MMBtu/hr (hourly average during boiler startup), and 451 MMBtu/hr (average for first hour of process shutdown). Hours of operation are specified as 8,718 hr/yr (normal and process startup), 24 hr/yr (boiler startup), and 18 hr/yr (process shutdown). Calculations assume continuous operation of two boilers at full load with the third boiler held in reserve.

Emission factors for NO_X and CO correspond to emission concentrations of 4 ppmv and 5 ppmv at 3% excess oxygen (normal/shutdown) and 30 ppmv and 200 ppmv at 3% excess oxygen (startup). Emission factors for VOC and PM are taken from manufacturer's data. VOC factors assume the use of an oxidation catalyst. All PM is assumed to be $PM_{2.5}$. Emission factor for SO_2 is derived from the maximum expected sulfur content of treated natural gas used in the process. Emission factors for all HAP/TAP compounds except ammonia, benzene, formaldehyde, naphthalene, PAH, and toluene are taken from EPA AP-42, Section 1.4 "*Natural Gas Combustion*" (*7/98*). Emission rate for ammonia corresponds to ammonia slip of 10 ppmv at 3% excess oxygen. Emission factors for benzene, formaldehyde, naphthalene, PAH, and toluene are taken from VCAPCD memorandum "*AB 2588 Combustion Emission Factors*" (*5/17/01*). Calculations do not assume any reduction by the oxidation catalyst so emission rates are considered to be conservative.

Emission factor for CO_2e from natural gas combustion is taken from 40 CFR 98. Emission estimate of process generated CO_2e is based on design parameters and flows at beginning of life for process catalyst. Combined CO_2e emissions are greatest at beginning of life.

Pollutant		Emission Factor (lb/MMBtu)	Emissions / Boiler (lb/hr)	Emissions / Boiler (tpy)	Combined Emissions (tpy)
NO_X	Regular	0.0049	2.60	11.34	22.68
	Startup	0.0364	4.84	0.06	0.12
CO	Regular	0.0037	1.98	8.56	17.13
	Startup	0.1478	19.66	0.24	0.47
VOC	Regular	0.0025	1.33	5.79	11.57
	Startup	0.02	10.60	0.03	0.06
SO_2		0.0000059	0.003	0.01	0.03
PM/PM_{10}		0.006	3.18	13.90	27.79
$PM_{2.5}$		0.006	3.18	13.90	27.79
CO_2e	Nat Gas	117	62,010	270,963	541,926
	Process		6,963	30,500	61,000

Pollutant	Emission Factor (lb/MMBtu)	Emissions / Boiler (lb/hr)	Emissions / Boiler (lb/yr)	Combined Emissions (lb/yr)
Ammonia	--	2.4	21,024	42,048
Benzene	1.67E-06	0.0009	7.7	15.5
Copper	8.33E-07	0.0004	3.9	7.7
Formaldehyde	3.53E-06	0.0019	16.4	32.8
Naphthalene	2.85E-07	0.0002	1.3	2.6
Nickel	2.05E-06	0.0011	9.5	19.0
PAH	3.79E-07	0.0002	1.8	3.6
Toluene	7.65E-06	0.0041	35.4	70.9

6.b <u>Power Generation Units.</u> Potential emissions from power generation unit (PGU) operation are calculated from specified heat input rates, proposed hours/modes of operation, and applicable emission factors. Annual emissions from PGU operation will be calculated based on actual fuel consumption, operating modes, and applicable emission factors.

Heat input rates for each PGU are specified as 453 MMBtu/hr (combustion turbine) and 105 MMBtu/hr (duct burner). Hours of operation are specified as 8,760 hr/yr with six 1-hr startups and six 1-hr shutdowns.

NO_X, CO, and VOC emission factors for regular operation correspond to emission concentrations of 2.5 ppmv, 4.0 ppmv and 3.0 ppmv at 15% excess oxygen, respectively. NO_X, CO, and VOC emission factors for startup and shutdown are taken from test data at a similar facility. SO_2 emission factor is derived from a sulfur content of 2.07 gr/100 scf (hourly) and 1.05 gr/100 scf (annual). PM emission factor is taken from vendor's data. All PM is assumed to be $PM_{2.5}$. CO_2e emission factor is taken from 40 CFR 98.

Combustion turbine emission factors for all HAP/TAP compounds except ammonia are taken from EPA AP-42, Section 3.1 "*Stationary Gas Turbines*". Duct burner emission factors for all HAP/TAP compounds except ammonia, benzene, formaldehyde, naphthalene, PAH, and toluene are taken from EPA AP-42, Section 1.4 "*Natural Gas Combustion*". Emission rate for ammonia corresponds to ammonia slip of 2 ppmv at 3% excess oxygen. Duct burner emission factors for benzene, formaldehyde, naphthalene, PAH, and toluene are taken from VCAPCD memorandum "*AB 2588 Combustion Emission Factors*" (*5/17/01*)

Pollutant		Emission Factor (lb/MMBtu)	Emissions / PGU (lb/hr)	Emissions / PGU (tpy)	Combined Emissions (tpy)
NO_X		0.00904	5.4	22.10	44.20
	Startup		9.6	0.03	0.06
	Shutdown		3.2	0.01	0.02
CO		0.0088	5.3	21.52	43.04
	Startup		5.7	0.02	0.03
	Shutdown		1.9	0.01	0.01
VOC		0.00377	2.3	9.22	18.44
	Startup		6.0	0.02	0.04
	Shutdown		2.0	0.01	0.01
SO_2		0.007 / 0.00356	3.9	8.70	17.41
	Startup		2.7	0.01	0.02
	Shutdown		2.7	0.01	0.02
$PM/PM_{10}/PM_{2.5}$		0.0066 (CT) 0.0072 (DB)	3.8	16.41	32.82
	Startup		2.5	0.01	0.02
	Shutdown		2.5	0.01	0.02
CO_2e		117	65,309	286,055	572,110

Pollutant	Emission Factor CT/DB (lb/MMBtu)	Emissions / PGU (lb/hr)	Emissions / PGU (lb/yr)	Combined Emissions (lb/yr)
Acetaldehyde	4.00E-05 / --	1.81E-02	159.7	319.4
Acrolein	6.40E-06 / --	2.90E-03	25.6	51.1
Ammonia	-- / --	1.6	13,064	26,128
Benzene	1.20E-05 / 5.69E-06	6.03E-03	53.0	106.0
Copper	-- / 8.33E-07	8.75E-05	0.7	1.5
Ethylbenzene	3.20E-05 / --	1.45E-02	127.8	255.5
Formaldehyde	1.07E-04 / 1.21E-05	4.95E-02	436.1	872.1
Naphthalene	1.30E-06 / 2.94E-07	6.20E-04	5.5	10.9
Nickel	-- / 2.06E-06	2.16E-04	1.8	3.7
PAH	2.20E-06 / 3.92E-07	1.04E-03	9.1	18.3
Toluene	1.30E-04 / 2.60E-05	6.16E-02	542.4	1,084.7
Xylenes	6.40E-05 / 1.93E-05	2.90E-02	272.9	545.7

6.c Process Heaters. Potential emissions from operation of the process heaters are calculated from specified heat input rates, proposed hours of operation, and applicable emission factors. Annual emissions from process heater operation will be calculated from actual fuel consumption and applicable emission factors.

Heat input rates for each boiler are specified as 74.4 MMBtu/hr (process startup) and 58 MMBtu/hr (process shutdown). Calculations assume six 28-hr startups and six 2-hr shutdowns per year.

NO_X and CO emission factors are taken from manufacturer's data. VOC and PM emission factors are taken from EPA AP-42, Section 1.4 "*Natural Gas Combustion*". All PM is assumed to be $PM_{2.5}$. SO_2 emission factor is derived from a sulfur content of 2.07 gr/100 scf (hourly) and 1.05 gr/100 scf (annual). Emission factor for CO_2e is taken from 40 CFR 98. Emission factors for all HAP/TAP compounds except benzene, formaldehyde, and toluene are taken from EPA AP-42, Section 1.4 "*Natural Gas Combustion*". Emission factor for benzene, formaldehyde, and toluene are taken from VCAPCD memorandum "*AB 2588 Combustion Emission Factors*" (*5/17/01*)

Pollutant	Emission Factor (lb/MMBtu)	Emissions / Heater (lb/hr)	Emissions / Heater (tpy)	Combined Emissions (tpy)
NO_X	0.032	2.38	0.21	0.42
CO	0.0325	2.42	0.21	0.43
VOC	0.0052	0.39	0.03	0.07
SO_2	0.007 / 0.0036	0.52	0.02	0.05
$PM/PM_{10}/PM_{2.5}$	0.0072	0.54	0.05	0.10
CO_2e	117	8,705	772	1,544

Pollutant	Emission Factor (lb/MMBtu)	Emissions / Heater (lb/hr)	Emissions / Heater (lb/yr)	Combined Emissions (lb/yr)
Benzene	5.69E-06	4.23E-04	0.08	0.16
Copper	8.33E-07	6.20E-05	0.01	0.02
Formaldehyde	1.21E-05	8.97E-04	0.16	0.32
Nickel	2.05E-06	1.53E-04	0.03	0.06
Toluene	2.60E-05	1.93E-03	0.34	0.68

6.d Process Flare Pilot. Potential emissions from operation of the process flare pilot are calculated from specified heat input rate, proposed hours of operation, and applicable emission factors. Annual emissions from pilot operation will be calculated based on actual fuel consumption and applicable emission factors.

Heat input rate for the process flare pilot is specified as 0.333 MMBtu/hr. Hours of operation are specified as 8,760 hr/yr.

NO_X, CO, and VOC emission factors are taken from EPA AP-42, Section 13.5 "*Industrial Flares*". PM emission factor is based on data from refinery flares at other facilities. All PM is assumed to be $PM_{2.5}$. SO_2 emission factor is derived from a sulfur content of 2.07 gr/100 scf (hourly) and 1.05 gr/100 scf (annual). Emission factor for CO_2e is taken from 40 CFR 98. Emission factors for all HAP/TAP compounds except benzene, formaldehyde, and toluene are taken from EPA AP-42, Section 1.4 "*Natural Gas Combustion*" (*7/98*). Emission factors for benzene, formaldehyde, and toluene are taken from VCAPCD memorandum "*AB 2588 Combustion Emission Factors*" (*5/17/01*)

Pollutant	Emission Factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (tpy)
NO_X	0.068	0.02	0.10
CO	0.31	0.10	0.45
VOC	0.14	0.05	0.20
SO_2	0.007 / 0.0036	0.001	0.005
$PM/PM_{10}/PM_{2.5}$	0.01	0.003	0.015
CO_2e	117	39	171

Pollutant	Emission Factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (lb/yr)
Benzene	1.56E-04	5.19E-05	0.46
Copper	8.33E-07	2.77E-07	0.002
Formaldehyde	1.15E-03	3.83E-04	3.36
Nickel	2.05E-06	6.83E-07	0.006
Toluene	5.69E-05	1.89E-05	0.17

6.e <u>Process Flare.</u> Potential emissions from operation of the process flare are calculated from specified heat input rates, proposed hours of operation, and applicable emission factors. Annual emissions from flare operation will be calculated based on actual heat input and applicable emission factors.

Maximum hourly total heat input rates are specified as 2,549 MMBtu/hr (process startup), 3,447 MMBtu/hr (process shutdown), 507 MMBtu/hr (process upset), and 6,148 MMBtu/hr (emergency process shutdown). Maximum hourly non-hydrogen heat input rates are specified as 586 MMBtu/hr (process startup), 1,308 MMBtu/hr (process shutdown), 317 MMBtu/hr (process upset), and 1,777 MMBtu/hr (emergency process shutdown). Average total heat input rates are specified as 1,008 MMBtu/hr (process startup) and 1,487 MMBtu/hr (process shutdown). Average non-hydrogen heat input rates are specified as 285 MMBtu/hr (process startup) and 615 MMBtu/hr (process shutdown).

Emissions of NO_X, SO_2, and PM are calculated based on total heat input. Emissions of CO, VOC, and CO_2e are calculated based on non-hydrogen heat input. Calculations assume six 22-hr process startups, four 6-hr process shutdowns, four 4-hr process upsets, and two 2-hr emergency process shutdowns. Hourly HAP/TAP calculations are based on worst case condition (emergency process shutdown). Annual HAP/TAP calculations are based on total heat input for all modes.

NO_X, CO, and VOC emission factors are taken from EPA AP-42, Section 13.5 "*Industrial Flares*". PM emission factor is based on data from refinery flares at other facilities. All PM is assumed to be $PM_{2.5}$. SO_2 emission factor is derived from the maximum expected sulfur content of treated natural gas used in the process. Emission factor for CO_2e is taken from 40 CFR 98. Emission factors for all HAP/TAP compounds except benzene, formaldehyde, and toluene are taken from EPA AP-42, Section 1.4 "*Natural Gas Combustion*" (*7/98*). Emission factors for benzene, formaldehyde, and toluene are taken from VCAPCD memorandum "*AB 2588 Combustion Emission Factors*" (*5/17/01*)

Pollutant		Emission Factor (lb/MMBtu)	Emissions (lb/hr)	Emissions (tpy)
NO_X		0.068		6.85
	Startup		173.3	
	Shutdown		234.4	
	Upset		34.5	
	Emerg Shutdown		418.1	
CO		0.31		10.01
	Startup		181.7	
	Shutdown		405.5	
	Upset		98.3	
	Emerg Shutdown		550.9	
VOC		0.57		18.40
	Startup		334.0	
	Shutdown		745.6	
	Upset		180.7	
	Emerg Shutdown		1,012.9	
SO_2		0.0000059		0.001
	Startup		0.015	
	Shutdown		0.020	
	Upset		0.003	
	Emerg Shutdown		0.036	
$PM/PM_{10}/PM_{2.5}$		0.01		1.01
	Startup		25.5	
	Shutdown		34.5	
	Upset		5.1	
	Emerg Shutdown		61.5	
CO_2e		117		3,777
	Startup		68,562	
	Shutdown		153,036	
	Upset		37,089	
	Emerg Shutdown		207,909	

Pollutant	Emission Factor (lb/MMBtu)	Emissions (max lb/hr)	Emissions (lb/yr)
Benzene	1.56E-04	0.96	31.4
Copper	8.33E-07	0.0051	0.2
Formaldehyde	1.15E-03	0.071	231.7
Nickel	2.05E-06	0.013	0.4
Toluene	5.69E-05	0.35	11.4

6.f Cooling Tower Potential emissions from cooling tower operation are calculated from maximum dissolved solids content and specified design parameters, using mass balance methodology. Annual emissions will be calculated from tested dissolved solids content and actual hours of operation.

Cooling tower parameters are specified as 260,400 gpm water circulation rate and maximum drift of 0.0005%. Maximum total dissolved solids content is 1,248 ppmw. Calculations assume 8,760 hr/yr of operation and a water weight of 8.27 lb/gal. PM emissions are assumed to be 76.7% PM_{10} and 0.23% $PM_{2.5}$ based on Reisman-Frisbie methodology.

Pollutant	Emissions (lb/hr)	(tpy)
PM	0.81	3.53
PM_{10}	0.62	2.71
$PM_{2.5}$	0.002	0.008

6.g Storage Tank Fugitives - Methanol. Potential fugitive emissions from methanol storage tank operation are calculated using the EPA TANKS emissions program, specified tank configurations, and proposed methanol throughput. Annual emissions will be calculated from actual methanol throughput using the same methodology.

Calculations assume total methanol throughput of 3,649,416 metric tons per year. Throughput is split evenly among tanks in each category. Hourly emissions are calculated by dividing annual emissions by 8,760 hr/yr. All VOC is assumed to be methanol. Affected tanks are assumed to be equipped with 99% efficient vapor capture systems.

Pollutant	Tank Type	Tank Count	Emissions / Tank (lb/hr)	(tpy)	Combined Emissions (tpy)
CO	Crude	2	0.0008	0.004	0.007
	Shift	4	--		
	Product	8	--		
VOC	Crude	2	0.28	1.23	2.46
	Shift	4	0.003	0.013	0.054
	Product	8	0.0004	0.002	0.015
CO_2e	Crude	2	0.007	0.032	0.063
Methanol (total)			0.28 lb/hr		2.53 tpy

6.h Equipment Component Fugitives - Methanol. Potential fugitive emissions from component leaks are calculated from proposed component counts and 8,760 hr/yr of operation using *Protocol for Equipment Leak Estimates* (EPA 453-R95-017, Nov 1995). Annual emissions will be calculated based on actual component counts and hours of operation using the same methodology. All VOC emissions are assumed to be methanol.

Pollutant	Emissions (lb/hr)	(tpy)
CO	0.009	0.04
VOC	0.13	0.55
CO_2e	2.63	11.5
Methanol	0.13	0.55

6.i Storage Tank Scrubber - Methanol. Potential vent emissions from methanol storage tank operation are calculated using the EPA TANKS emissions program, specified tank configurations, and proposed methanol throughput. Annual emissions will be calculated from actual methanol throughput using the same methodology.

Calculations assume total methanol throughput of 3,649,416 metric tons per year. Throughput is split evenly among tanks in each category. Hourly emissions are calculated by dividing annual emissions by 8,760 hr/yr. Storage tank ventilation system has a rated capture efficiency of 99%. Manufacturer's data indicates the wet scrubber will remove 99% of methanol from the captured vent stream. All CO emissions are assumed to pass through the wet scrubber uncontrolled. All VOC emissions are assumed to be methanol.

Pollutant	Emissions (lb/hr)	(tpy)
CO	0.17	0.72
VOC	0.58	2.50
CO_2e	1.42	6.22
Methanol	0.58	2.50

6.j Marine Vessel Loading Scrubber - Methanol. Potential vent emissions from ship loading operations are calculated from specified system parameters, loading emission calculations from AP-42, Section 5.2, and proposed methanol throughput. Annual emissions will be calculated from actual methanol throughput using the same methodology.

Calculations assume total methanol throughput of 3,649,416 metric tons per year. Uncontrolled emissions are ~0.030 kg/mton per Equation 1 of Section 5.2. The ship loading system is configured with a vapor capture system and wet scrubber with an overall methanol control efficiency of 99%. All VOC emissions are assumed to be methanol.

Pollutant	Emissions (lb/hr)	(tpy)
VOC	1.94	1.21
Methanol	1.94	1.21

6.k Storage Tank Fugitives - Ammonia. Potential fugitive emissions from ammonia storage tank operation are calculated using the EPA TANKS emissions program, specified tank configurations, and proposed ammonia throughput. Annual emissions will be calculated from actual ammonia throughput using the EPA Tanks emissions program.

Calculations total ammonia throughput of 684,762 gallons per year. Throughput is split evenly among all tanks. Hourly emissions are calculated by dividing annual emissions by 8,760 hr/yr. All emissions are assumed to be ammonia.

Pollutant	Tank Count	Emissions / Tank (lb/hr)	(tpy)	Combined Emissions (tpy)
Ammonia	3	0.105	0.46	1.38

6.1 Diesel Engines - Emergency Generators #1 and #2. Potential emissions from emergency generator operation are calculated from rated engine power, proposed operation, and applicable emission factors. Annual emissions will be calculated from actual operation using the same methodology.

Individual engines are rated at 4,628 hp. Calculations assume 52 hr/yr of operation. NO_X, VOC, and PM emission factors correspond to the applicable EPA Tier 4 Final emission standards for non-emergency engines. All PM is assumed to be $PM_{2.5}$. CO emission factor is taken from emission data for a representative engine (Caterpillar C175-20). SO_2 emission factor is calculated from maximum fuel sulfur content using a formula from EPA AP-42, Table 3.4-1. Maximum fuel sulfur content is 0.0015% sulfur by weight. CO_2e emission factor is taken from 40 CFR 98, Subpart C.

Pollutant	Emission Factor lb/hp-hr	Single Engine (lb/hr)	Single Engine (tpy)	Combined Emissions (tpy)
NO_X	1.65E-03	7.65	0.20	0.40
CO	7.94E-04	3.67	0.10	0.19
VOC	3.97E-04	1.84	0.05	0.10
SO_2	1.21E-05	0.056	0.001	0.003
$PM_{10}/PM_{2.5}$	7.50E-05	0.35	0.01	0.02
CO_2e	163.6 (lb/MMBtu)	5,784	150	301

6.m Diesel Engine - Fire Pump #1. Potential emissions from fire pump operation are calculated from rated engine power, proposed operation, and applicable emission factors. Annual emissions will be calculated from actual operation using the same methodology.

The engine is rated at 1,600 hp. Calculations assume 56 hr/yr of operation. All emission factors except SO_2 are taken from manufacturer's data for a representative engine (Clarke JW6H-UFADF0). All PM is assumed to be $PM_{2.5}$. SO_2 emission factor is calculated from maximum fuel sulfur content using a formula from EPA AP-42, Table 3.4-1. Maximum fuel sulfur content is 0.0015% sulfur by weight. CO_2e emission factor is taken from 40 CFR 98, Subpart C.

Pollutant	Emission Factor lb/hp-hr	Emissions (lb/hr)	Emissions (tpy)
NO_X	5.73E-03	9.17	0.26
CO	1.76E-03	2.82	0.08
VOC	2.20E-04	0.35	0.01
SO_2	1.21E-05	0.019	0.001
$PM_{10}/PM_{2.5}$	2.20E-04	0.35	0.01
CO_2e	163.6 (lb/MMBtu)	1,772	50

6.n Emissions Summary/Facilitywide Potential to Emit. Facilitywide potential to emit as calculated in the sections above is summarized below.

Pollutant	Emissions (tpy)	Project Increase (tpy)
NO_X	75.10	75.10
CO	72.60	72.60
VOC	55.68	55.68
SO_2	17.52	17.52
Lead	--	--
PM	65.31	65.31
PM_{10}	64.49	64.49
$PM_{2.5}$	61.79	61.79
HAP	8.63	8.63
TAP	44.11	44.11
CO_2e	1,180,897	1,076,000* (*voluntary limit taken by source*)

Pollutant	CAS Number	Toxics Category	Facilitywide Emissions (lb/yr)	Incremental Increase (lb/yr)	WAC 173-460 SQER (lb/yr)
Acetaldehyde	*75-07-0*	*HAP/TAP A*	*319.4*	*319.4*	*50*
Acrolein	107-02-8	HAP/TAP B	51.1	51.1	175
Ammonia	*7664-41-7*	*TAP B*	*70,936*	*70,936*	*17,500*
Benzene	*71-43-2*	*HAP/TAP A*	*153.5*	*153.5*	*20*

Pollutant	CAS Number	Toxics Category	Facilitywide Emissions (lb/yr)	Incremental Increase (lb/yr)	WAC 173-460 SQER (lb/yr)
Copper	7440-50-8	TAP B	9.4	9.4	175
Ethylbenzene	100-41-4	HAP/TAP B	255.5	255.5	43,748
Formaldehyde	*50-00-0*	*HAP/TAP A*	*1,140*	*1,140*	*20*
Methanol	67-56-1	HAP/TAP B	13,577	13,577	43,748
Naphthalene	91-20-3	HAP/TAP B	13.5	13.5	22,750
Nickel	*7440-02-0*	*HAP/TAP A*	*23.2*	*23.2*	*0.5*
PAH	--	*HAP/TAP A*	*21.8*	*21.8*	*0*
Toluene	108-88-3	HAP/TAP B	1,168	1,168	43,748
Xylene	1330-20-7	HAP/TAP B	545.7	545.7	43,748

7. REGULATIONS AND EMISSION STANDARDS

Regulations that have been used to evaluate the acceptability of the proposed facility and establish emission limits and control requirements include, but are not limited to, the regulations, codes, or requirements listed below.

7.a Title 40 Code of Federal Regulations Part 60 (40 CFR 60) Subpart Db "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" applies to steam generating units with a heat input greater than 100 MMBtu/hr constructed, modified, or reconstructed after June 19, 1984. The proposed process boilers meet the definition of a steam generating unit, have a rated heat input greater than 100 MMBtu/hr, and will be constructed after June 19, 1984. Therefore, the process boilers at this facility will be subject to this regulation.

7.b 40 CFR 60 Subpart Dc "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units" applies to steam generating units with a heat input greater than or equal to 10 million Btu/hr, but less than or equal to 100 million Btu/hr constructed, modified, or reconstructed after June 9, 1989. The proposed process heaters do not meet the definition of a steam generating unit. Therefore, this regulation is not applicable to the process heaters at this facility.

7.c 40 CFR 60 Subpart Kb "Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984" applies to storage vessels with a capacity greater than or equal to 75 m^3 (19,812 gallons) but less than 151 m^3 storing volatile organic liquids (VOL) with a maximum true vapor pressure (TVP) greater than or equal to 15.0 kilopascal (kPa), or storage vessels with a capacity greater than 151 m^3 (39,900 gallons) storing VOL with a maximum TVP of greater than or equal to 3.5 kPa. The proposed methanol storage tanks (crude, shift, product) have a capacity greater than 39,900 gallons and will store a VOL with a maximum true vapor pressure greater than 3.5 kPa. Therefore, this regulation is applicable to the methanol tanks at this facility. The proposed ammonia storage tanks store material that is not a VOL. Therefore, this regulation is not applicable to the ammonia storage tanks at this facility.

7.d 40 CFR 60 Subpart VVa "Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry" applies to equipment in VOC service at SOCMI facilities constructed, modified, or reconstructed after November 7, 2006. This facility will be in service for methanol (a listed chemical) and has a design capacity larger than the exemption threshold. Therefore, this regulation is applicable to the facility. The facility has chosen to comply with the requirements of this regulation by complying with the requirements of 40 CFR 63, Subpart H as allowed by 40 CFR 60.480(e)(2).

7.e 40 CFR 60 Subpart NNN "Standards of Performance for VOC Emissions From SOCMI Distillation Operations" applies to distillation units producing any chemical listed in 40 CFR 60.667 as a product, co-product, by-product or intermediate that was constructed, modified, or reconstructed after December 30, 1983. The distillation units at this facility are new units used to produce methanol (a listed chemical). Therefore, this regulation is applicable to the distillation units at this facility.

7.f 40 CFR 60 Subpart RRR "Standards of Performance for VOC Emissions from SOCMI Reactor Processes" applies to reactor process units producing any chemical listed in 40 CFR 60.667 as a product, co-product, by-product or intermediate that was constructed, modified, or reconstructed after June 29, 1990. The synthesis gas converters at this facility are new process units producing methanol (a listed chemical). Therefore, this regulation is applicable to the synthetic gas converters and associated recovery equipment at this facility.

7.g 40 CFR 60 Subpart CCCC "Commercial and Industrial Solid Waste Incinerators Constructed After November 30, 1999; or Modified or Reconstructed on or After June 1, 2001" establishes requirements for commercial and industrial solid waste incineration (CISWI) units. This regulation could potentially apply to the process boilers because they combust vent streams (flash & purge gases) from the facility's distillation units. However, the definition of "solid waste" (40 CFR 258.2) does not include uncontained gaseous material so the vent streams do not qualify as solid waste. Therefore, this regulation does not apply to the process boilers at this facility.

7.h 40 CFR 60 Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines" applies to compression ignition (CI) internal combustion engines (ICEs) constructed after July 11, 2005 and manufactured after April 1, 2006, or modified or reconstructed after July 11, 2005. The diesel engines that power the proposed emergency generators and fire pump are compression ignition internal combustion engines manufactured after April 1, 2006. Therefore, this regulation is applicable to those diesel engines.

7.i 40 CFR 60 Subpart KKKK "Standards of Performance for Stationary Combustion Turbines" applies to combustion turbines with a heat input at peak load greater than or equal to 10 MMBtu/hr constructed, modified or reconstructed after February 18, 2005. Under this regulation, the definition of "stationary combustion turbine" includes the combustion turbine as well as any ancillary components and sub-components of a combined cycle turbine installation. The combustion turbines in the power generation units are new units with a peak heat input greater than 10 MMBtu/hr. Therefore, this regulation applies to the power generation units at this facility. Pursuant to 40 CFR 60.4305(b), heat recovery generators and duct burners associated with the power generation units are subject to this regulation and exempt from 40 CFR 60, Subpart Db.

7.j 40 CFR 61 Subpart FF "National Emission Standard for Benzene Waste Operations" applies to chemical manufacturing plants and other sources that treat, store, or dispose of hazardous waste generated by associated operations. The primary factor in determining applicability of control requirements is the facility's total annual benzene (TAB), which is the sum of the annual benzene quantity for each waste stream at the facility. The proposed facility meets the definition of a chemical manufacturing plan so it is subject to this regulation. Based on proposed operating data, the facility's TAB is expected to be less than 1 Mg/yr. A facility with a TAB less than 1 Mg/yr is required to maintain documentation of the benzene waste in its waste, but is not subject to any other requirements.

7.k 40 CFR 63 Subpart F "National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry" applies to chemical manufacturing process units that manufacture as a primary product one or more of the chemicals listed in the regulation, use as a reactant or manufacture as a product, or co-product, one or more of the organic hazardous air pollutants listed in the regulation, and are located at a plant site that is a major source of HAP. This facility is an area source of HAP. Therefore, this rule is not applicable to this facility.

7.l 40 CFR 63 Subpart G "National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater applies to affected units at facilities that manufacture as a primary product one or more of the chemicals listed in the regulation, use as a reactant or manufacture as a product, or co-product, one or more of the organic hazardous air pollutants listed in the regulation, and are located at a plant site that is a major source of HAP. This facility is an area source of HAP. Therefore, this rule is not applicable to this facility.

7.m 40 CFR 63 Subpart H "National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks" applies to a wide range of equipment at major sources of HAP that are intended to operate in organic hazardous air pollutant service for 300 hours or more during the calendar year. The proposed facility is not a major source of HAP so this regulation is not directly applicable. However, NWIWK has chosen to comply with the requirements of 40 CFR 63, Subpart H in lieu of meeting the requirements of 40 CFR 60, Subpart VVa. Therefore, this regulation will be applicable to the facility.

7.n 40 CFR 63 Subpart Q "National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers" applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources of HAP or are integral parts of facilities that are major sources of HAP. The cooling tower at this facility will not use chromium-based water treatment chemicals and the facility is an area source of HAP. Therefore, this regulation is not applicable to the cooling tower at this facility.

7.o 40 CFR 63 Subpart Y "National Emission Standards for Marine Tank Vessel Loading Operations" applies to major sources of HAP loading marine tank vessels with a throughput of greater than 1.6 billion liters (10 M barrels) of gasoline annually or 32 billion liters (200 M barrels) of crude oil annually. This facility is an area source of HAP and does not handle gasoline or crude oil. Therefore, this regulation is not applicable to marine loading operations at this facility.

7.p 40 CFR 63 Subpart EEE "Hazardous Waste Combustors" applies to sources that operate a hazardous waste combustor. This regulation could potentially apply to the process boilers because they combust vent streams (flash & purge gases) from the facility's distillation units. Similar to 40 CFR 60 Subpart CCCC, SWCAA has determined that the vent streams do not qualify as "solid waste" (40 CFR 261.2). Therefore, this regulation does not apply to the process boilers at this facility.

7.q 40 CFR 63 Subpart EEEE "National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)" applies to major sources of HAP performing organic liquids distribution (OLD) operations. OLD operations include the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity being performed. This facility is an area source of HAP. Therefore, this regulation is not applicable to this facility.

7.r 40 CFR 63 Subpart FFFF "National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing" applies to miscellaneous organic chemical manufacturing process units (MCPU) that are located at, or are part of, a major source of HAP. This facility is an area source of HAP. Therefore, this regulation is not applicable to this facility.

7.s 40 CFR 63 Subpart YYYY "National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines" establishes HAP limits, testing, monitoring, recordkeeping and reporting requirements for turbines located at a major source of HAP. This facility is an area source of HAP. Therefore, this regulation is not applicable to the combustion turbines at this facility.

7.t 40 CFR 63 Subpart ZZZZ "National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines" establishes national emission limitations and operating limitations for HAP emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP. The diesel engines that power the proposed emergency generators and fire pump meet the definition of a new stationary compression ignition reciprocating internal combustion engine, which is an affected facility. Therefore, this regulation is applicable to those diesel engines. Pursuant to 40 CFR 63.6590(c)(1), the engines will comply with the regulation by complying with the requirements of 40 CFR 60 Subpart IIII. No other requirements from this regulation are applicable.

7.u 40 CFR 63 Subpart DDDDD "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters" applies to any Industrial, Commercial, and Institutional Boiler and Process Heater located at a major source of HAP that meets the applicability criteria and commences construction or reconstruction after January 13, 2003. This facility is an area source of HAP. Therefore, this regulation is not applicable to the process boilers at this facility.

7.v 40 CFR 63 Subpart JJJJJJ "National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources" establishes performance standards and requirements for industrial, commercial and institutional boilers operating at an area source of HAP. The process heaters at this facility do not meet the definition of a boiler, and are not subject. The process boilers meet the definition of a boiler, but fire on gaseous fuel only. Gas-fired boilers are not subject to the regulation so this regulation is not applicable to the process boilers at this facility.

7.w 40 CFR 63 Subpart VVVVVV "National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources" applies to chemical manufacturing process units at an area source of HAP that use feedstock containing affected chemicals or produce affected chemicals as a product or byproduct. Affected chemicals are listed in Table 1 of the subpart. The methanol making process at this facility uses only natural gas as a feedstock and does not produce any of the chemicals listed in Table 1 of the subpart. Therefore, this regulation is not applicable to this facility.

7.x 40 CFR 68 "Chemical Accident Prevention Provisions" requires affected stationary sources to compile and submit a risk management plan, as provided in Sections 68.150 to 68.185. Applicability is determined by the type and quantity of material stored at the facility. The Part 68 material of concern for this facility is aqueous ammonia stored onsite for use in the combustion turbine and boiler SCR systems. The 40 CFR 68.130 threshold for ammonia is 20,000 lbs. Proposed ammonia storage is potentially 27,000 lbs (3 tanks @ 9,000 gallons each). Therefore, this regulation is applicable to this facility.

7.y Revised Code of Washington (RCW) 70.94.141 empowers any activated air pollution control authority to prepare and develop a comprehensive plan or plans for the prevention, abatement and control of air pollution within its jurisdiction. An air pollution control authority may issue such orders as may be necessary to effectuate the purposes of the Washington Clean Air Act [RCW 70.94] and enforce the same by all appropriate administrative and judicial proceedings subject to the rights of appeal as provided in Chapter 62, Laws of 1970 ex. sess.

7.z RCW 70.94.152 provides for the inclusion of conditions of operation as are reasonably necessary to assure the maintenance of compliance with the applicable ordinances, resolutions, rules and regulations when issuing an Air Discharge Permit for installation and establishment of an air contaminant source.

7.aa Washington Administrative Code (WAC) 173-401 "Operating Permit Regulation" requires all major sources and other sources as defined in WAC 173-401-300 to obtain an operating permit. This regulation is not applicable because this source is not a major source and does not meet the applicability criteria set forth in WAC 173-401-300.

7.bb WAC 173-442 "Clean Air Rule" establishes GHG emissions standards starting in 2017 for certain stationary sources, petroleum product producers/importers, and natural gas distributors. The proposed facility will have covered GHG emissions in excess of the thresholds listed in WAC 173-442-030. Therefore, this regulation is applicable to this facility. Implementation of the regulation will be carried out separately by the Department of Ecology so SWCAA's permitting action does not address related program requirements.

7.cc WAC 173-460 "Controls for New Sources of Toxic Air Pollutants" requires Best Available Control Technology for toxic air pollutants (T-BACT), identification and quantification of emissions of toxic air pollutants and demonstration of protection of human health and safety. SWCAA implements WAC 173-460 as in effect on August 21, 1998.

7.dd WAC 173-476 "Ambient Air Quality Standards" establishes ambient air quality standards for PM_{10}, $PM_{2.5}$, lead, sulfur dioxide, nitrogen dioxide, ozone, and carbon monoxide in the ambient air, which shall not be exceeded.

7.ee SWCAA 400-040 "General Standards for Maximum Emissions" requires all new and existing sources and emission units to meet certain performance standards with respect to Reasonably Available Control Technology (RACT), visible emissions, fallout, fugitive emissions, odors, emissions detrimental to persons or property, sulfur dioxide, concealment and masking, and fugitive dust.

7.ff SWCAA 400-040(1) "Visible Emissions" requires that no emission of an air contaminant from any emissions unit shall exceed twenty percent opacity for more than three minutes in any one hour at the emission point, or within a reasonable distance of the emission point.

7.gg SWCAA 400-040(2) "Fallout" requires that no emission of particulate matter from any source shall be deposited beyond the property under direct control of the owner(s) or operator(s) of the source in sufficient quantity to interfere unreasonably with the use and enjoyment of the property upon which the material is deposited.

7.hh SWCAA 400-040(3) "Fugitive Emissions" requires that reasonable precautions be taken to prevent the fugitive release of air contaminants to the atmosphere.

7.ii SWCAA 400-040(4) "Odors" requires that any person who shall cause or allow the generation of any odor from any source, which may unreasonably interfere with any other property owner's use and enjoyment of their property use recognized good practices and procedures to reduce these odors to a reasonable minimum.

7.jj SWCAA 400-040(6) "Sulfur Dioxide" requires that no person shall emit a gas containing in excess of one thousand ppm of sulfur dioxide on a dry basis, corrected to 7% O_2 or 12% CO_2 as required by the applicable emission standard for combustion sources.

7.kk SWCAA 400-040(8) "Fugitive Dust Sources" requires that reasonable precautions be taken to prevent fugitive dust from becoming airborne, and minimize emissions.

7.ll SWCAA 400-050 "Emission Standards for Combustion and Incineration Units" requires that all provisions of SWCAA 400-040 be met and that no person shall cause or permit the emission of particulate matter from any combustion or incineration unit in excess of 0.23 grams per dry cubic meter (0.1 grains per dry standard cubic foot) of exhaust gas at standard conditions.

7.mm SWCAA 400-060 "Emission Standards for General Process Units" prohibits particulate matter emissions from all new and existing process units in excess of 0.1 grains per dry standard cubic foot of exhaust gas.

7.nn SWCAA 400-091 "Voluntary Limits on Emissions" allows sources to request voluntary limits on emissions and potential to emit by submittal of an ADP application as provided in SWCAA 400-109. Upon completion of review of the application, SWCAA shall issue a Regulatory Order that reduces the source's potential to emit to an amount agreed upon between SWCAA and the permittee.

7.oo SWCAA 400-110 "New Source Review" requires that an Air Discharge Permit Application be filed with SWCAA, and an Air Discharge Permit be issued by SWCAA, prior to establishment of the new source, emission unit, or modification.

7.pp SWCAA 400-113 "Requirements for New Sources in Attainment or Nonclassifiable Areas" requires that no approval to construct or alter an air contaminant source shall be granted unless it is evidenced that:

(1) The equipment or technology is designed and will be installed to operate without causing a violation of the applicable emission standards;
(2) Best Available Control Technology will be employed for all air contaminants to be emitted by the proposed equipment;
(3) The proposed equipment will not cause any ambient air quality standard to be exceeded; and
(4) If the proposed equipment or facility will emit any toxic air pollutant regulated under WAC 173-460, the proposed equipment and control measures will meet all the requirements of that Chapter.

8. RACT/BACT/BART/LAER/PSD/CAM DETERMINATIONS

The proposed equipment and control systems incorporate Best Available Control Technology (BACT) for the types and amounts of air contaminants emitted by the processes as described below:

8.a BACT Determination – Power Generation Units. The proposed use of the following control measures has been determined to meet the requirements of BACT and T-BACT for the power generation units at this facility:

General Good combustion practices.

NO_X/NH_3 Low-NO_X combustors and a selective catalytic reduction system capable of limiting exhaust gas concentrations of NO_X to 2.5 ppmvd @ 15% O_2. Control measures will be operated in such a manner that stack emissions of ammonia will not exceed 2.0 ppmvd @ 15% O_2.

CO/VOC An oxidation catalyst system capable of limiting exhaust gas concentrations of CO to 4.0 ppmvd @ 15% O_2 and concentrations of VOC to 3.0 ppmvd @ 15% O_2.

PM/SO_2 A fuel with low ash and sulfur content (pipeline natural gas).

8.b BACT Determination – Process Boilers. The proposed use of the following control measures has been determined to meet the requirements of BACT and T-BACT for the process boilers at this facility:

General Good combustion practices.

NO_X/NH_3 Low-NO_X burners and a selective catalytic reduction system with ammonia injection capable of limiting exhaust gas concentrations of NO_X to 4.0 ppmvd @ 3% O_2. Control measures will be operated in such a manner that stack emissions of ammonia will not exceed 10 ppmvd @ 3% O_2.

CO/VOC An oxidation catalyst system capable of limiting exhaust gas concentrations of CO to 5.0 ppmvd @ 3% O_2 and concentrations of VOC to 6.0 ppmvd @ 3% O_2.

PM/SO_2 A fuel with low ash and sulfur content (pipeline natural gas and process gas).

8.c BACT Determination – Process Heaters. The proposed use of the following control measures has been determined to meet the requirements of BACT and T-BACT for the process heaters at this facility:

General Good combustion practices.

NO_X A burner design incorporating flue gas recirculation capable of limiting exhaust gas concentrations of NO_X to 30 ppmvd @ 3% O_2.

CO/VOC A burner design capable of limiting exhaust gas concentrations of CO to 45.0 ppmvd @ 3% O_2 and concentrations of VOC to 14.0 ppmvd @ 3% O_2.

PM/SO_2 A fuel with low ash and sulfur content (pipeline natural gas).

8.d BACT Determination – Process Flare. The proposed use of proper design and operation, good combustion practices, and low sulfur assist gas (natural gas) has been determined to meet the requirements of BACT and T-BACT for the process flare at this facility

8.e BACT Determination – Methanol Storage. The proposed use of internal floating roof tank designs, vapor capture systems, and high efficiency wet scrubbing has been determined to meet the requirements of BACT and T-BACT for methanol storage tanks at this facility.

8.f BACT Determination – Marine Vessel Loading. The proposed use of submerged fill, vapor balancing, and high efficiency wet scrubbing has been determined to meet the requirements of BACT and T-BACT for marine vessel loading operations at this facility.

8.g BACT Determination – Equipment Component Leaks. The proposed use of a leak detection and repair program that complies with the provisions of 40 CFR 63, Subpart H has been determined to meet the requirements of BACT and T-BACT for fugitive leaks from equipment components handling volatile organic compounds at this facility.

8.h BACT Determination – Ammonia Storage. The proposed use of properly sized secondary containment and equipment designed to minimize spill related emissions has been determined to meet the requirements of BACT and T-BACT for aqueous ammonia storage tanks at this facility.

8.i BACT Determination – Cooling Tower. The use of high-efficiency drift eliminators and routine monitoring of total dissolved solids (TDS) in the cooling water has been determined to meet the requirements of BACT and T-BACT for cooling towers at this facility.

8.j BACT Determination – Emergency Generators / Fire Pump. The proposed use of a modern diesel engine design (EPA Tier certified), limited hours of operation (testing, maintenance, and emergency use only), and ultra-low sulfur fuel (less than 0.0015% sulfur by weight) has been determined to meet the requirements of BACT and T-BACT for the diesel engine powered emergency generators and fire pump at this facility.

Other Determinations

8.k Prevention of Significant Deterioration (PSD) Applicability Determination: The potential to emit of this facility is less than applicable PSD applicability thresholds. Likewise, this permitting action will not result in a potential increase in emissions equal to or greater than the PSD thresholds. Therefore, PSD review is not applicable to this action.

8.l Compliance Assurance Monitoring (CAM) Applicability Determination. CAM is not applicable to any emission unit at this facility because it is not a major source and is not required to obtain a Part 70 permit.

9. AMBIENT IMPACT ANALYSIS

9.a TAP Small Quantity Review. The incremental increases in TAP emissions associated with this permitting action are quantified in Section 6.n of this Technical Support Document. All incremental increases in individual TAP emissions are less than the applicable small quantity emission rate (SQER) identified in WAC 173-460 (effective 8/21/98) with the exception of acetaldehyde, ammonia, benzene, formaldehyde, nickel, and PAH.

9.b TAP Ambient Impact Analysis. Incremental increases in TAP emissions that exceeded the applicable SQER were modeled using the AERMOD (version 15181) model. The results of the model indicate that the project will not cause an incremental increase in ambient concentrations greater than the applicable acceptable source impact level (ASIL) identified in WAC 173-460 (effective 8/21/98).

Toxic Compound	CAS #	Incremental Ambient Impact (μg/m^3)	Acceptable Source Impact Level (μg/m^3)	Averaging Period
Acetaldehyde	75-07-0	0.0014	0.45	Annual
Ammonia	7664-41-7	28	100	24-hr
Benzene	71-43-2	0.00056	0.12	Annual
Formaldehyde	50-00-0	0.0040	0.077	Annual
Nickel	7440-02-0	0.00038	0.0021	Annual
PAH	--	0.00010	0.00048	Annual

Conclusions

9.c Installation and operation of a methanol production facility, as proposed in ADP Application CO-964, will not cause the ambient air quality requirements of Title 40 Code of Federal Regulations (CFR) Part 50 "National Primary and Secondary Ambient Air Quality Standards" to be violated.

9.d Installation and operation of a methanol production facility, as proposed in ADP Application CO-964, will not cause the requirements of WAC 173-460 "Controls for New Sources of Toxic Air Pollutants" (as in effect 8/21/98) or WAC 173-476 "Ambient Air Quality Standards" to be violated.

9.e Installation and operation of a methanol production facility, as proposed in ADP Application CO-964, will not cause a violation of emission standards for sources as established under SWCAA General Regulations Sections 400-040 "General Standards for Maximum Emissions," 400-050 "Emission Standards for Combustion and Incineration Units," and 400-060 "Emission Standards for General Process Units."

10. DISCUSSION OF APPROVAL CONDITIONS

SWCAA has made a determination to issue ADP 16-3204 in response to ADP Application CO-964. ADP 16-3204 contains approval requirements deemed necessary to assure compliance with applicable regulations and emission standards as discussed below.

10.a General Basis. Permit requirements for equipment affected by this permitting action incorporate the expected operational performance and operating schemes proposed by the applicant in ADP Application CO-964. Permit requirements established by this action are intended to implement BACT, minimize emissions, and assure compliance with applicable requirements on a continuous basis. Emission limits for approved equipment are based on the maximum potential emissions calculated in Section 6 of this Technical Support Document.

10.b Monitoring and Recordkeeping Requirements. ADP 16-3204 establishes monitoring and recordkeeping requirements sufficient to document compliance with applicable emission limits, ensure proper operation of approved equipment and provide for compliance with generally applicable requirements.

10.c Reporting Requirements. ADP 16-3204 establishes general reporting requirements for air emissions, upset conditions and excess emissions. Specific reporting requirements are established for hours of operation, fuel consumption, and material throughput. Reports are to be submitted on a quarterly basis.

10.d Power Generation Units. The proposed power generation units incorporate combustion turbines with low emission combustors and add-on catalyst systems. Emission limits are based on manufacturer's data/guarantees. The combustion turbines and associated catalyst systems are not capable of achieving optimum performance during startup or shutdown. Permit conditions impose alternate short term emission limits during these periods. The alternate limits are time limited and based on test data from similar facilities. Each unit will be equipped with emission monitoring systems for NO_X, CO and ammonia.

10.e Process Boilers. The proposed boilers are equipped with low emission burner assemblies and add-on catalyst systems. Emission limits are based on manufacturer's data/guarantees. The catalyst systems associated with the boilers are not capable of achieving optimum performance during startup or shutdown. Permit conditions impose alternate short term emission limits during these periods. The alternate limits are time limited and based on data from the manufacturer. Each unit will be equipped with emission monitoring systems for NO_X, CO and ammonia.

10.f Process Heaters. Operation of the process heaters is limited to process startup and shutdown periods, which is expected to occur only a few times per year. The proposed process heaters are equipped with low emission burner assemblies. Emission limits for NO_X, CO and VOC are based on manufacturer's guarantees. Periodic emission monitoring requirements have been established for the purposes of demonstrating compliance with applicable emission limits.

10.g Process Flare. Operation of the process flare is expected to be fairly limited. However, the conditions under which the flare will potentially operate vary greatly. As a result, short term emission limits for the unit also vary greatly. Annual emission limits are based on the worst case design conditions summarized in Section 6 of this technical support document. There are no emission testing requirements for the flare due to its configuration and operating conditions.

10.h Changes Between Draft and Final Permits. Selected descriptions and permit requirements in the draft permit and technical support document have been revised in response to public comment prior to final issuance of ADP 16-3204. The revisions are as follows:

- Descriptions of the ammonia storage tanks in the permit and technical support document were revised for consistency. All bulk ammonia storage tanks have a vertical configuration.
- The ZLD process was added to Section 5 of the technical support document as an insignificant emission unit.
- Small corrections were made to unit specific emission estimates of process generated CO_2e in Section 6 of the technical support document. The corrections did not change the voluntary facilitywide limit requested by the applicant.
- Emission limits in the permit were revised to clarify applicability on a rolling 12-month basis.
- Specific citation of the flare design and operational requirements of 40 CFR 63.11(b) was added to the permit.
- A requirement to install, maintain and operate a monitoring system for gas flow and heat input to the flare was added to the permit.
- A requirement for marine tank vessels to be in dedicated service or purged/cleaned prior to loading was added to the permit.
- A requirement to formally develop operational procedures to monitor for heat exchanger leaks was added to the permit.
- The "date of last vapor tightness certification" was added to the list of required records for marine tank vessels in the permit.
- A general requirement to provide sampling platforms and safe testing access pursuant to 40 CFR 60.8(e) was added to the permit.
- The proposed schedule of periodic VOC testing and parametric monitoring for the methanol wet scrubbers was changed to a requirement to install, maintain and operate a continuous emission rate monitoring system (*CERMS*) for VOC emissions from the wet scrubbers.

- The testing schedule for VOC and PM emissions from the power generation units and process boilers was changed from once every 5 years to a two tier schedule requiring annual testing for a minimum period of 3 years with an allowance for future testing once every 5 years upon repeated demonstration of compliance.
- An appendix containing quality assurance and quality control requirements for the wet scrubber VOC CERMS was added to the permit.

11. START-UP AND SHUTDOWN/ALTERNATIVE OPERATING SCENARIOS/POLLUTION PREVENTION

11.a Start-up and Shutdown Provisions. Pursuant to SWCAA 400-081 "Start-up and Shutdown", technology based emission standards and control technology determinations shall take into consideration the physical and operational ability of a source to comply with the applicable standards during start-up or shutdown. Where it is determined that a source is not capable of achieving continuous compliance with an emission standard during start-up or shutdown, SWCAA shall include appropriate emission limitations, operating parameters, or other criteria to regulate performance of the source during start-up or shutdown.

Power Generation Unit Startup. The proposed power generation units utilize catalyst systems to minimize emissions of NO_X, CO and VOC. The catalyst systems do not function at maximum efficiency until minimum operating temperatures and flows are established. Consequently, manufacturer's guaranteed emissions cannot be met during startup and shutdown. Alternate emission limits are applicable during these operating periods.

Process Boiler Startup. The proposed process boilers utilize catalyst systems to minimize emissions of NO_X, CO and VOC. The catalyst systems do not function at maximum efficiency until minimum operating temperatures and flows are established. Consequently, manufacturer's guaranteed emissions cannot be met during startup and shutdown. Alternate emission limits are applicable during these operating periods.

Diesel Engines (Emergency Generators / Fire Pump). Visible emissions from diesel engine power units are limited to 5% opacity or less during normal operation. However, the engine is not capable of reliably limiting visible emissions to less than 5% opacity until the engine achieves normal operating temperature. Therefore, the 5% opacity limit shall not apply to the generator exhaust during start-up periods.

11.b Alternate Operating Scenarios.

Process Flare. The primary methanol production process requires an extended period of time to achieve steady state operation. Under normal operating conditions, there is no exhaust flow to the process flare. During startup/shutdown periods and process upsets, gas streams from the various production processes are disposed of in the process flare. Flowrate, gas composition and, heat input rate vary greatly depending on the scenario, which causes process flare emissions to vary greatly. Four separate operating modes have been identified in the permit. Each operating mode has corresponding emission limits.

11.c Pollution Prevention Measures. SWCAA conducted a review of possible pollution prevention measures for the facility. No pollution prevention measures were identified by either the permittee or SWCAA separate or in addition to those measures required under BACT considerations. Therefore, none were included in the permit requirements.

12. EMISSION MONITORING AND TESTING

12.a Emission Testing - Power Generation Units. Permit requirements for the power generation units require the permittee to conduct emission testing on an annual basis for the purposes of demonstrating compliance with applicable emission limits. All emission testing shall be conducted in accordance with the provisions of ADP 16-3204, Appendix A.

12.b Continuous Monitoring Requirements - Power Generation Units. Permit requirements for the power generation units require the permittee to install and maintain continuous monitoring systems for emissions of NO_X, CO, and O_2. Continuous monitoring systems shall be operated and maintained in accordance with ADP 16-3204, Appendix B. All continuous monitoring systems shall be equipped with a data acquisition and handling system (DAHS) to monitor and record emission concentrations and rates of each pollutant.

12.c Fuel Sulfur Monitoring - Power Generation Units. The sulfur content of natural gas fired in the combustion turbine/HRSG will be determined annually in accordance with ADP 16-3204, Appendix C.

12.d Emission Testing - Process Boilers. Permit requirements for the process boilers require the permittee to conduct emission testing on an annual basis for the purposes of demonstrating compliance with applicable emission limits. All emission testing shall be conducted in accordance with the provisions of ADP 16-3204, Appendix D.

12.e Continuous Monitoring Requirements - Process Boilers. Permit requirements for the process boilers require the permittee to install and maintain continuous monitoring systems for emissions of NO_X, CO, and O_2. Continuous monitoring systems shall be operated and maintained in accordance with ADP 16-3204, Appendix B. All continuous monitoring systems shall be equipped with a data acquisition and handling system (DAHS) to monitor and record emission concentrations and rates of each pollutant.

12.f Fuel Sulfur Monitoring - Process Boilers. The sulfur content of fuel gas fired in the process boilers will be determined in accordance with a site-specific fuel sulfur analysis plan.

12.g Emission Monitoring - Process Heaters. Permit requirements for the process heaters require the permittee to conduct emission monitoring concurrent with each process startup for the purposes of demonstrating compliance with applicable emission limits. All emission testing shall be conducted in accordance with the provisions of ADP 16-3204, Appendix E.

12.h Emission Testing - Methanol Wet Scrubbers. Permit requirements for the methanol wet scrubbers require the permittee to conduct emission testing on an annual basis for the purposes of demonstrating compliance with applicable emission limits. All emission testing shall be conducted in accordance with the provisions of ADP 16-3204, Appendix F.

12.i Continuous Monitoring Requirements - Methanol Wet Scrubbers. Permit requirements for the methanol wet scrubbers require the permittee to install and maintain continuous emission rate monitoring systems for emissions of VOC. Continuous monitoring systems shall be operated and maintained in accordance with ADP 16-3204, Appendix G. All continuous monitoring systems shall be equipped with a data acquisition and handling system (DAHS) to monitor and record emission concentrations and rates of each pollutant.

12.j Emission Monitoring Requirements – Cooling Tower. The total dissolved solids (TDS) content of water in the cooling tower will be determined at least once per quarter by averaging the results of not less than 3 individual water samples.

13. FACILITY HISTORY

13.a Previous Permitting Actions. SWCAA has not previously issued any permits for the proposed methanol production facility in Kalama, Washington:

13.b Compliance History. A search of source records on file at SWCAA did not identify any outstanding compliance issues at this facility.

14. PUBLIC INVOLMENT OPPORTUNITY

14.a Public Notice for ADP Application CO-964. Public notice for ADP Application CO-964 was published on the SWCAA internet website for a minimum of (15) days beginning on March 23, 2016.

14.b Public/Applicant Comment for ADP Application CO-964. SWCAA provided a 30 day public comment period and a public hearing for the preliminary determination to approve ADP Application CO-964. The public comment period for the preliminary determination to approve ADP Application CO-964 began on November 11, 2016 and ended on February 6, 2017. The public hearing for the preliminary determination to approve ADP Application CO-964 was held on January 4, 2017 at the Cowlitz PUD auditorium in Longview, Washington.

14.c Summary of Public Comment and Comment Response for ADP Application CO-964. During the comment period a total of 1,035 public comments were received via letter, email, and personal delivery. Oral testimony was given by 69 citizens at the public hearing. Original comments and a transcript of the oral testimony is on file at SWCAA's business office. Public comment and testimony is summarized in the attached *Public Comment and Comment Response* document for ADP Application CO-964. Testimony given at the public hearing has been included with other public comment received during the comment period.

14.d State Environmental Policy Act. The Port of Kalama and Cowlitz County are serving as co-lead agencies for the proposed project. NWIWK has provided the lead agencies with project information necessary to support the development of an Environmental Impact Statement (EIS). The lead agencies issued a draft EIS for the proposed project on March 3, 2016. The comment period for the draft EIS ended on April 18, 2016. A final EIS was issued on September 30, 2016.