PERMIT APPLICATION

Moses Lake Industries, Inc. > Moses Lake, WA

Notice of Construction

TMAC Product Quality and Emissions Upgrade Project

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1. EXECUTIVE SUMMARY

Moses Lake Industries, Inc. (MLI) operates a tetramethyl ammonium carbonate (TMAC) production facility in Moses Lake, Washington. This facility is currently subject to Approval Order No. 16AQ-E022, which was issued by the Department of Ecology – Eastern Regional Office (Ecology) on September 1, 2016. MLI is proposing to upgrade its existing TMAC production facility to improve product quality and reduce potential emissions. As part of this upgrade project, MLI will also install a new boiler (Boiler #2) to provide additional utility steam capacity and reliability for MLI process operations. Section 2 of this application provides a detailed description of the proposed upgrade project.

Based on its potential to emit (PTE), MLI's TMAC production facility is currently considered a minor source with respect to the Prevention of Significant Deterioration (PSD) permitting program, a minor source with respect to the Title V operating permit program, and an area source of Hazardous Air Pollutant (HAP) emissions. Emission calculations for the proposed project are presented in Section 3 of this application. As described in Section 4, the proposed project will not affect these designations. Therefore, this project does not require a PSD or Title V permit application.

As provided in Washington Administrative Code (WAC) 173-400-110 173-400-110, a Notice of Construction (NOC) Order of Approval, often referred to as minor New Source Review (NSR), is still required. This application satisfies the NOC application requirements. In addition to the general application requirements, the proposed upgrade project will be subject to certain federal and state regulations including New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and the Washington Toxic Air Pollutant (TAP) rules. These regulations are addressed in Section 4 of this report.

As part of the NOC application, a Best Available Control Technology (BACT) analysis is conducted for criteria pollutant emissions from new and modified equipment associated with the proposed project in accordance with WAC 173-400-141. Pollutants with project-related increases that exceed the NSR exemption thresholds established by WAC 173-400-110(5) are addressed by the BACT evaluation. Additionally, in accordance with WAC 173-460-060, a similar BACT evaluation is required for Toxic Air Pollutant (TAP) emissions that exceed the pollutant-specific de minimis thresholds established by WAC 173-460-150. Section 5 of this application presents the BACT determinations for relevant criteria pollutants and the TAP BACT (tBACT) determinations for relevant TAPs.

As a requirement for new sources of TAPs under WAC 173-460, a TAP screening analysis is performed in accordance with the methodology established by WAC 173-460-080. As presented in Section 2 of this application, the results of the analysis demonstrate that emissions of each TAP are below its respective Small Quantity Emission Rate (SQER), with the exception of NO_2. Accordingly, project-related emissions of NO_2 are modeled using AERSCREEN and the results of this dispersion modeling analysis are presented in Section 6.

The final section of this application, Section 7, identifies MLI's requested changes to existing permit limits.

In summary, the NOC application contains the following elements:

- Section 2. Project Description
- Section 3. Emission Calculations
- Section 4. Regulatory Applicability
- Section 5. BACT/tBACT Evaluation
- Section 6. Dispersion Modeling Analysis

- Section 7. Requested Permit Changes
- Appendix A: Application Forms
- Appendix B: Site Plan
- Appendix C: Emission Calculations
- Appendix D: BACT Cost Calculations
- Appendix E: Boiler Vendor Documentation
- Appendix F: Modeling Files and Results
- Appendix G: Revised Permit Table
- Appendix H: SEPA checklist

2. PROJECT DESCRIPTION

MLI is proposing to upgrade its existing TMAC production facility in Moses Lake, Washington to improve product quality and reduce potential emissions. As part of this upgrade project, MLI will also install a new boiler (Boiler #2) to provide additional utility steam capacity and reliability for MLI process operations including the TMAC Plant. The following section provides a detailed project description and identifies equipment affected by the proposed upgrade project.

2.1. PROJECT DESCRIPTION

2.1.1. Project Impact on TMAC Production Rate

The current facility is permitted to produce 2,207 kg/hour (30-day average) of pure TMAC, with no single day production to exceed 128,520 lb/day (58,312 kg/day). The upgrades are designed to achieve a consistent high-quality production of 2,034 kg/hour (30-day average) of pure TMAC, with no single day production to exceed 118,445 lb/day (53,740 kg/day). As such, the upgraded TMAC production rates will remain below the maximum levels listed in the existing Order.

2.1.2. TMAC Process Upgrades

The following upgrades are proposed for the TMAC process at the Moses Lake facility:

1. MLI will increase the size of vaporizer purification process equipment for incoming raw materials. This upgrade will minimize the potential for trace metals carry-through and improve TMAC product quality by minimizing the potential generation of off-specification product.
2. MLI will rearrange the reactor vessels to balance flows and increase residence time of raw materials in the reactor system. This upgrade will minimize the potential for any unreacted materials to exit the reactor system. As such, this change will also minimize potential loading to the reactor vent condensers E-105 and E-205. Following the upgrades, each of the two TMAC production lines will have two parallel reactor trains, where each reactor train consists of one small followed by one large reactor vessel. In total, this will result in a facility reactor system consisting of four small and four large reactor vessels.
3. MLI will enhance the proportional feed control valving strategy to minimize the potential flow rate to the reactor vent condensers E-105 and E-205.
4. MLI will add a new reactor vent condenser (E-105B) to the process, which will be sized 50% larger than the existing Line 2 vent condenser (E-205) and approximately seven (7) times larger than the existing Line 1 vent condenser (E-105[1]). The new vent condenser will be added in series after the existing vent condenser E-105 and equipped with an integral mist eliminator. Therefore, following the upgrade project, the volumetric capacity of the Line 1 reactor vent condenser system will increase by a factor of approximately eight (8). In combination with the series arrangement of the condenser system and the associated integral mist eliminator, this will provide the Line 1 process with a robust reactor vent condenser system that can handle increased venting relative to the existing system.
5. MLI will install a reactor vent condenser cross-over line between Line 1 and Line 2 of the TMAC production process. While the previously described vent condenser system upgrade is anticipated to provide a robust level of excess capacity, if needed, the cross-over line can be utilized to provide additional condenser volume to address any periodic higher flows from either line.

[1] Following the upgrade project, the existing reactor vent condenser E-105 will be renamed E-105A.

6. MLI will install a similar distillation column vent condenser cross-over line between the Line 1 E-119 and the Line 2 E-219 equipment. E-219 is approximately 4.7 times the size of E-119 and will provide a very robust back-up condenser capability for the Line 1 distillation condenser capacity.
7. MLI will install a mass flow meter in the inlet line to the flare to provide additional information on flows and comparison to the individual vent flows from E-105, E-205, E-119 and E-219.
8. MLI will convert the existing -15 °C brine (methanol/water) chiller system to use glycol/water. This chiller system will also be upgraded in size to support the additional condenser and process loads.
9. MLI will upgrade the distillation columns for Line 1 and Line 2 with a higher efficiency packing material. The packing will improve the separation efficiency achieved by the distillation columns at a lower reflux ratio. Reducing the reflux ratio reduces the energy load associated with the distillation column reboiler and condenser. This change has a positive benefit relative to steam and chiller demand, while improved separation efficiency will reduce overhead loading from the distillation columns to the vent condensers.

From a project timing standpoint, MLI anticipates that the initial phase will focus on the Line 1 process improvements including the raw material purification upgrades, chiller utility upgrade, reactor condenser flow modulation, E-105A/E-105B upgrade, cross-over piping, Line 1 reactor rearrangement, flare inlet flow metering and Line 1 column packing upgrade. Boiler #2 will be installed during this initial phase to support the Line 1 upgrades. MLI anticipates that the second phase will implement the same process improvements for Line 2, except that the purification and utility work will have already been completed.

2.1.3. Boiler #2

In addition to the aforementioned process upgrades, MLI will install a new boiler, which will be referred to as Boiler #2. This boiler will have the capability to combust both natural gas and the co-product methanol stream generated by the facility. Boiler #2 will have a heat input capacity of approximately 16.7 MMBtu/hr and will be equipped with Low NO_x burners and a Flue Gas Recirculation (FGR) system to minimize NO_x emissions. To support the emission estimates identified in Section 3 of this application, MLI is requesting a methanol usage limit for Boiler #2 of 1,201,000 gallons per year.

In addition to supplementing the TMAC facility's steam generating capacity, the addition of this boiler will ensure that the facility is able to use all methanol co-product on-site for energy recovery. By combusting this material on-site, as opposed to shipping it off-site, the risk of spills and leaks during transportation is eliminated and fugitive emissions associated with shipping the product off-site are avoided.

3. PROJECT EMISSION CALCULATIONS

This section describes each source of emissions increases associated with the TMAC process upgrade project, as well as the methodologies used to calculate criteria pollutant, HAP, and TAP emissions from each source. Detailed supporting calculations can be found in Appendix C.

3.1. PROJECT-RELATED EMISSIONS SOURCES

3.1.1. Boiler #2

Detailed emission calculations for Boiler #2 are presented in Section C1 of Appendix C. These emission calculations are based on guarantees from Cole Industrial (the boiler vendor) for CO and NO_x emissions, which vary by fuel type. Emissions of other criteria pollutants associated with natural gas combustion are calculated using the appropriate sections of EPA's AP-42. Filterable PM emissions from methanol combustion are based on the regulatory limit for new boilers combusting liquid fuels under 40 CFR 63 Subpart JJJJJJ. Emissions of other criteria pollutants during methanol combustion are assumed to be equivalent to natural gas emissions.

Per Ecology's request, TAP and HAP emissions from natural gas combustion are calculated using emission factors obtained from the Ventura County Air Pollution Control District's AB 2588 Combustion Emission Factors document. MLI has used its process knowledge to estimate worst-case TMA and methanol emissions from combusting the co-product methanol stream in the new boiler. The sum total of TMA and methanol emissions is assumed to represent the VOC emission rate for methanol combustion in Boiler #2.

As MLI is requesting a methanol usage limit for Boiler #2 of 1,201,000 gallons per year, the potential annual emissions of each pollutant are calculated based on whichever of the following scenarios results in a higher annual emission rate:

- <u>Scenario 1</u>: Firing natural gas at the boiler's maximum capacity for 8,760 hours per year
- <u>Scenario 2</u>: Firing methanol at the proposed operating limit and firing natural gas the remainder of the time at the boiler's maximum capacity

Additional details and the results of these calculations are presented in Section C1 of Appendix C.

3.1.2. Additional Fugitive Components

Project-related increases of fugitive emissions associated with leaks from new piping components are calculated using past actual monitoring data and very conservative assumptions. Specifically, MLI determined the maximum actual piping fugitive emission rate reported by the Moses Lake facility between 2012 and 2017. This maximum actual emission rate was then doubled to approximate the potential emission rate from existing piping components. A factor of 25% was then applied to the resulting potential emission rate to determine emissions from new project-related piping components. Because the specific counts of new piping components will be substantially less than 25% of the counts of existing piping components, this calculation method is conservative. Additional details and the results of these calculations are presented in Section C2 of Appendix C.

3.2. POTENTIAL TO EMIT FOR PROJECT

Table 3-1 identifies project-related potential emission increases for the proposed TMAC upgrade project.

Table 3-1. Project Emissions

Source	PM (filterable) (tpy)	$PM_{10}/PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	VOC (tpy)	CO (tpy)	CO_2e (tpy)	Methanol (tpy)
Boiler #2	1.16	0.54	0.04	6.17	0.94	3.97	8,563	0.50
Additional Fugitive Components	--	--	--	--	0.97	--	--	0.81
Project Totals	***1.16***	***0.54***	***0.04***	***6.17***	***1.91***	***3.97***	***8,563***	***1.31***
NSR Exemption Thresholds[2]	1.25	0.75/0.5	2.0	2.0	2.0	5.0	--	See Table 3-2
Project Emissions Above Thresholds?	No	Yes (for $PM_{2.5}$)	No	Yes	No	No	--	See Table 3-2

3.3. TOXIC AIR POLLUTANT ANALYSIS

Ecology regulates the emissions of TAPs through the provisions of WAC 173-460. TAPs are listed in WAC 173-460-150 with a SQER, acceptable source impact level (ASIL), and de minimis threshold for each pollutant, which are used to demonstrate compliance with WAC 173-460. For the proposed TMAC upgrade project, the only sources of TAP emissions are the new boiler and additional fugitive components. However, as discussed elsewhere in this NOC application, MLI is proposing to redistribute and/or reduce the annual emission limits for existing sources such that the upgrade project will not result in an increase in facility-wide permitted methanol or TMA emissions.

Table 3-2 shows project-related emissions increases of each TAP, which are compared to the de minimis threshold and/or SQER for each respective pollutant. Table 3-2 shows that all TAPs emitted from the project are below their respective SQERs with the exception of NO_2. A dispersion modeling evaluation for project emissions of NO_2 is presented in Section 6 of this application. Additional details regarding this TAPs screening evaluation is presented in Section C4 of Appendix C.

[2] NSR exemption thresholds are established by WAC 173-400-110(5). For TAP emissions such as methanol, the de minimis emission rates specified in WAC 173-460-150 represent the NSR exemption thresholds.

Table 3-2. Project-Related TAP Emissions

Pollutant	CAS Number	Emissions		Averaging Period	ASIL (µg/m³)	SQER (lb/avg. period)	De Minimis (lb/avg. period)	Modeling Required?
		Maximum Hourly TAPs (lb/hr)	Maximum Annual TAPs (tpy)					
Benzene	71-43-2	9.40E-05	4.12E-04	year	0.0345	6.62	0.331	No
Formaldehyde	50-00-0	1.99E-04	8.73E-04	year	0.167	32	1.6	No
Naphthalene	91-20-3	4.86E-06	2.13E-05	year	0.0294	5.64	0.282	De Minimis
Acetaldehyde	75-07-0	5.03E-05	2.20E-04	year	0.37	71	3.55	De Minimis
Acrolein	107-02-8	4.38E-05	1.92E-04	24-hr	0.06	0.00789	0.000394	No
Propylene	115-07-1	8.59E-03	0.04	24-hr	3000	394	19.7	De Minimis
Toluene	108-88-3	4.30E-04	1.88E-03	24-hr	5000	657	32.9	De Minimis
Xylene	108-38-3	3.19E-04	1.40E-03	24-hr	221	29	1.45	De Minimis
Ethylbenzene	100-41-4	1.12E-04	4.90E-04	year	0.4	76.8	3.84	De Minimis
Hexane	110-54-3	7.46E-05	3.27E-04	24-hr	700	92	4.6	De Minimis
Methanol	67-56-1	0.41	1.31	24-hr	4000	526	26.3	De Minimis
SO_2	7446-09-05	9.73E-03	0.04	1-hr	660	1.45	0.457	De Minimis
NO_2	10102-44-0	2.22	6.17	1-hr	470	1.03	0.457	**Yes**
CO	630-08-0	1.21	3.97	1-hr	23000	50.4	1.14	No

MLI's TMAC production facility is located in Moses Lake, Grant County, Washington, which is in attainment for all criteria pollutants. The following sections evaluate the air quality-related regulatory requirements potentially applicable to the proposed TMAC facility upgrade project.

4.1. FEDERAL NEW SOURCE REVIEW

A project in an attainment area is subject to the Prevention of Significant Deterioration (PSD) permitting program under Washington Administrative Code (WAC) 173-400-700 if the project is either a "major modification" to an existing "major source," or is a new major source itself. MLI's existing TMAC production facility falls below the threshold criteria for classification as a major PSD source. As such, PSD applicability is triggered only if the upgrade project would constitute a major stationary source by itself. In other words, the upgrade project must increase emissions of a regulated air pollutant by 100 tons per year (tpy) or more to trigger PSD review.[3] Therefore, potential emission increases of each criteria air pollutant must be compared to the PSD major source thresholds. Table 4-1 compares the potential emission increases for the proposed upgrade project at MLI's TMAC production facility and demonstrates that PSD permitting (i.e., federal NSR) is not triggered for the project.

Table 4-1. PSD Major Source Threshold Comparison

Source	PM (filterable) (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Project Emissions	1.16	0.54	0.54	0.04	6.17	3.97	1.91
PSD Emission Thresholds	100	100	100	100	100	100	100
Subject to PSD?	No	No	No	No	No	No	No

4.2. TITLE V OPERATING PERMITS

If the Potential to Emit (PTE) of the post-project facility exceeds the Title V major source threshold for any criteria pollutant, Hazardous Air Pollutant (HAP), or combination of HAPs, then Title V permitting requirements are triggered for the entire facility. Table 4-2 presents post-project potential facility emissions relative to the Title V major source thresholds. As demonstrated by this table, the post-project Moses Lake facility will not trigger Title V permitting requirements. The emission limits proposed by MLI in Section 7 of this application will ensure compliance with the annual emission rates.

[3] As a chemical process plant, MLI's Moses Lake facility is subject to a PSD major source threshold of 100 tons per year, as opposed to the general PSD major source threshold of 250 tons per year.

Table 4-2. Title V Major Source Threshold Comparison

Source	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)	Combined HAP (tpy)	Individual HAP-Methanol (tpy)
Facility-Wide PTE	<10	<10	<10	<10	20.7	8.0	21.74	<15	6.93
Title V Thresholds	100	100	100	100	100	100	100	25	10
Subject to Title V?	No	No	No	No	No	No	No	No	No

4.3. NOC APPLICABILITY

WAC 173-400-110 establishes requirements for a project that increases emissions of regulated air pollutants but does not trigger federal NSR permitting. This state-level permitting requirement is often referred to as minor NSR. If subject to minor NSR, a facility must submit a NOC application and obtain a corresponding order of approval before constructing a new source. A new source, as defined in WAC 173-400-030, is "the construction or modification of a stationary source that increases the amount of any air contaminant emitted by such source or that results in the emission of any air contaminant not previously emitted…"

With the exception of emission increases from the new boiler (Boiler #2) and minor new piping components, MLI's proposed upgrade project is expected to reduce actual emissions of regulated air pollutants from the Moses Lake facility by minimizing process vents controlled by the existing flare. However, Boiler #2 is an integral part of the facility upgrade project and must be considered in the project emission increase calculations. As demonstrated by Table 3-1, total project emissions (including Boiler #2) exceed the NSR exemption thresholds for NO_x and $PM_{2.5}$ emissions only. Consequently, the proposed project is considered a "new source" that triggers the requirements of WAC 173-400-110 and a NOC application is required. The requisite NOC application forms are presented in Appendix A.

When evaluating net emissions from the proposed project in concert with MLI's proposed emission limit redistribution strategy (as described in Section 7 of this application), the permitting action as a whole will result in small increases in the permit limits for facility-wide criteria pollutants and a decrease in the permit limit for facility-wide methanol emissions. The permit limit for facility-wide TMA emissions will remain unchanged.

4.4. BEST AVAILABLE CONTROL TECHNOLOGY

Under WAC 173-400-110, each new and/or modified source must employ BACT for all pollutants not previously emitted, or any pollutants for which emissions will increase as a result of the new source or modification. The proposed project will increase process emissions of VOC and TAPs from new fugitive piping components, and will cause various criteria pollutants and TAPs to be emitted from a new emission unit (i.e., Boiler #2).

As shown in Table 3-1 of this application, only project-related emissions of NO_x and $PM_{2.5}$ exceed the corresponding pollutant-specific NSR exemption thresholds established by WAC 173-400-110(5) and are subject to BACT requirements. Furthermore, as depicted in Table 3-2, project-related emissions of benzene, formaldehyde, acrolein, NO_2, and CO exceed the de minimis thresholds established by 173-460-150 and are subject to tBACT requirements. Project-related emissions of each of these pollutants are associated with Boiler #2 only. Therefore, Section 5 of this application presents a BACT/tBACT evaluation for emissions of NO_x/NO_2, $PM_{2.5}$, CO, and miscellaneous organic TAPs (i.e., benzene, formaldehyde, acrolein) from Boiler #2.

4.5. NEW SOURCE PERFORMANCE STANDARDS

WAC 173-400-115 adopts federal NSPS by reference. The NSPS rules, which are located in Title 40 of the Code of Federal Regulations Part 60 (40 CFR 60), require new, modified, or reconstructed sources to control emissions to the level achievable by the best-demonstrated technology as specified in the applicable provisions. The following is an evaluation of potentially applicable NSPS regulations for new and modified equipment associated with the proposed project.

4.5.1. 40 CFR Part 60 Subpart A, General Provisions

NSPS Subpart A, 40 CFR 60.18 (General Control Device Requirements) contains requirements for control devices used to comply with applicable NSPS subparts. As described in Sections 4.5.4 and 4.5.5, MLI's TMAC production facility uses a process flare as a control device for compliance with NSPS Subparts NNN and RRR. Accordingly, the flare must adhere to applicable provisions of 40 CFR 60.18. The proposed upgrade project will involve physical modifications to the reactor and distillation processes that feed the flare; however, these changes will not increase the system throughput beyond existing permitted rates, will not increase the venting rate to the flare at the permitted production rate, and will not affect the applicability of NSPS Subparts A, NNN, and RRR, as these subparts already apply to MLI's process equipment.

With respect to NSPS Subpart A requirements, the flare is designed to comply with all relevant requirements of 40 CFR 60.18, including visible emission limits, continuous flame requirements, minimum vapor heat content thresholds, and maximum exit velocity limits. These requirements are established by the current air permit for MLI's Moses Lake facility and will continue to apply following the upgrade project.

4.5.2. 40 CFR Part 60 Subpart Dc, New Source Performance Standards (NSPS) for Small Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Dc applies to steam generating units constructed, modified, or reconstructed after June 9, 1989 with a maximum design heat input capacity between 10 million British thermal units per hour (MMBtu/hr) and 100 MMBtu/hr (inclusive). The proposed new boiler will be rated at 16.7 MMBtu/hr and will be constructed in 2018. Therefore, Boiler #2 will be subject to the applicable requirements of NSPS Subpart Dc.

NSPS Subpart Dc regulates emissions of SO_2 and PM from steam generating units; however, the PM emission limit only applies to a unit with a heat input capacity of greater than 30 MMBtu/hr that is constructed, modified, or reconstructed after February 28, 2005. Given Boiler #2's capacity rating, the PM emission limit of NSPS Subpart Dc will not apply. Consequently, only the SO_2-related requirements of NSPS Subpart Dc will apply to Boiler #2.

The proposed Boiler #2 will combust either natural gas or the co-product methanol stream produced by MLI's facility. NSPS Subpart Dc establishes SO_2 standards for a unit based on fuel-type. Specifically, 40 CFR 60.42c sets SO_2 standards for the following categories of steam generating units:

- Units that combust only coal;
- Units that combust only coal refuse;
- Units that combust coal in combination with any other fuel;
- Units that combust only oil; and
- Units that combust coal, oil, or coal and oil with any other fuel.

40 CFR 60.41c defines *oil* as "crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil." The methanol co-product stream produced by MLI's Moses Lake facility does not meet the regulatory definition of *oil*. As such, Boiler #2 is not considered an oil-fired unit and is not subject to the SO_2 standards established by 40 CFR 60.42c.

The only other applicable requirements for the proposed boiler under NSPS Subpart Dc are the initial notification requirements identified in 40 CFR 60.7 and 60.48c(a), and the requirement to maintain records of fuels combusted in the units as required under 40 CFR 60.48c(g) and (i). MLI will comply with all applicable notification and recordkeeping requirements established by NSPS Subpart Dc and the corresponding General Provisions.

4.5.3. 40 CFR Part 60 Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

NSPS Subpart VVa provides standards for equipment leaks of VOC from process units that produce, as an intermediate or final product, any of the Synthetic Organic Chemical Manufacturing Industry (SOCMI) chemicals listed in 40 CFR 60.489. NSPS Subpart VVa applies to the specific component types specified in the rule (e.g., valves, pumps, agitators). In addition, the process unit is subject to NSPS Subpart VVa requirements only if it is considered to be new, modified, or reconstructed after November 7, 2006.

Fugitive piping components at the current TMAC production facility are subject to NSPS Subpart VV requirements. If the TMAC process is considered to be modified or reconstructed as a result of the proposed project, then all fugitive piping components associated with the TMAC process would become subject to NSPS Subpart VVa instead of Subpart VV. This determination is based on capital cost data for the project in comparison to the costs to construct an entirely new comparable TMAC process.

Based on conservative cost estimates, MLI has concluded that NSPS Subpart VVa requirements are triggered by the project. Therefore, MLI will upgrade its current NSPS Subpart VV compliance strategy to ensure compliance with applicable NSPS Subpart VVa requirements.

4.5.4. 40 CFR Part 60 Subpart NNN, Standards of Performance for Volatile Organic Compound Emissions from SOCMI Distillation Processes

NSPS Subpart NNN (Standards of Performance for Volatile Organic Compound Emissions From SOCMI Distillation Operations) applies to SOCMI facilities that produce, as intermediates or final products, any chemical included in 40 CFR 60.667. As methanol is included in 40 CFR 60.667 and is the major byproduct produced in the synthesis of TMAC, the distillation section of MLI's TMAC facility is subject to the requirements of this subpart. The distillation system will be physically modified as part of the project, but the applicability of NSPS NNN will not change based on this modification. MLI will continue to meet the Subpart NNN standard in 40 CFR 60.662(b) by controlling distillation process vent emissions by a closed-vent system routed to a condenser recovery system, which discharges to the existing process flare. The process flare will continue to comply with all applicable requirements of 40 CFR 60.18, as required by 40 CFR 60.662(b). This control system also complies with the applicable monitoring requirements of 40 CFR 60.663(b). Furthermore, MLI will continue to comply with all relevant reporting and recordkeeping requirements established by 40 CFR 60.665. These relevant requirements are established by MLI's current air permit.

4.5.5. 40 CFR Part 60 Subpart RRR, Standards of Performance for Volatile Organic Compound Emissions from SOCMI Reactor Processes

NSPS Subpart RRR (Standards of Performance for Volatile Organic Compound Emissions From SOCMI Reactor Processes) applies to SOCMI facilities that produce, as intermediates or final products, any chemical included in 40 CFR 60.707. As methanol is included in 40 CFR 60.707 and is the major byproduct produced in the synthesis of TMAC, the reaction section of MLI's TMAC facility upgrade project is subject to the requirements of this subpart. The reactor system will be physically modified as part of the project, but the applicability of NSPS RRR will not change based on this modification. MLI will continue to meet the Subpart RRR standards in 40 CFR 60.702(b) by controlling reaction process venting emissions by a closed-vent system routed to a condenser recovery system, which discharges to the existing process flare. The process flare will continue to comply with all applicable requirements of 40 CFR 60.18, as required by 40 CFR 60.702(b). This control system also complies with the applicable monitoring requirements of 40 CFR 60.703(b). Furthermore, MLI will continue to comply with all relevant reporting and recordkeeping requirements established by 40 CFR 60.705. These relevant requirements are established by MLI's current air permit.

4.6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The NESHAP rules, which are located in 40 CFR Part 61 and Part 63, require major sources of HAP emissions to control their HAP emissions. The standards established under 40 CFR 63 specifically establish Maximum Achievable Control Technology (MACT) requirements for specific source categories. As presented in Section 4.2 of this application, the Moses Lake facility is not a major source of HAPs and is therefore only potentially subject to "Area Source" NESHAP regulations. The following sections evaluate potentially applicable NESHAP regulations.

4.6.1. 40 CFR Part 61 Subpart V, Standards for Equipment Leaks (Fugitive Emission Sources)

40 CFR 61 Subpart V, National Emission Standard for Equipment Leaks (Fugitive Emission Sources), regulates fugitive equipment leaks for facilities processing certain chemicals that meet the regulatory definition of volatile hazardous air pollutants (VHAPs). According to the definitions for this subpart established by 40 CFR 61.241, the VHAP category is limited to benzene and vinyl chloride. As MLI's TMAC production facility does not operate any pumps, pressure relief devices, valves, or connectors in VHAP service, 40 CFR 61 Subpart V is not applicable to the Moses Lake facility.

4.6.2. 40 CFR Part 63 Subparts F and G, National Emission Standards for Organic HAPs from the SOCMI Industry

40 CFR 63 Subparts F (National Emission Standards for Organic Hazardous Air Pollutants from the SOCMI) and 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) regulate emissions of hazardous chemicals from SOCMI facilities that are classified as major sources of HAPs. Under Section 112(a) of the Clean Air Act, the term "major source" is defined as any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tpy or more of any HAP or 25 tpy or more of any combination of HAPs. Because MLI's post-project TMAC production facility will not be classified as a major source of hazardous air pollutants, 40 CFR 63 Subparts F and G are not applicable.

4.6.3. 40 CFR Part 63 Subpart JJJJJJ, National Emission Standards for HAPs for Area Sources: Industrial, Commercial, and Institutional Boilers

40 CFR 63 Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers) applies to industrial, commercial, and institutional boilers within the coal, biomass, or oil subcategory that are located at, or are part of, an area source of HAP, as defined in 40 CFR 63.2, except as specified in 40 CFR 63.11195.[4] 40 CFR 63.11237 specifies that the "*oil subcategory* includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories…" Furthermore, "*liquid fuel* includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil." Considering this broad definition of the term *liquid fuel*, the liquid methanol co-product stream produced by MLI would constitute a liquid fuel for the purposes of 40 CFR 63 Subpart JJJJJJ.

Therefore, Boiler #2 will be subject to the new unit oil subcategory requirements of 40 CFR 63 Subpart JJJJJJ.[5] The new boiler must meet the applicable emission limits established by Table 1 of the regulation, as well as the work practice standards established by Table 2 of the regulation. Specifically, MLI must meet the following requirements for the proposed boiler:

- Demonstrate compliance with a PM (filterable) emission limit of 0.03 lb/MMBtu of heat input;
- Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures;
- Conduct a tune-up biennially (i.e., every two years) as specified in 40 CFR 63.11223[6]; and
- Applicable notification and recordkeeping requirements.

To demonstrate compliance with the applicable PM limit, MLI would need to conduct periodic source testing in accordance with Table 4 of Subpart JJJJJJ. However, previous testing for Boiler #1 has demonstrated that the methanol co-product stream is an inherently low PM fuel, such that EPA waived the requirement for follow-up source testing on the existing boiler. MLI is in the process of petitioning EPA in an attempt to obtain a waiver from the PM testing requirements for Boiler #2. However, because this waiver has not been granted at the time of application submittal, MLI requests that the permit issued by Ecology include flexible language that requires MLI to either satisfy the applicable performance testing requirements of 40 CFR 63 Subpart JJJJJJ or demonstrate that such testing is not required through an EPA waiver.

4.7. STATE REGULATORY APPLICABILITY

4.7.1. Washington Toxic Air Pollutant Regulations

In Washington, all new sources emitting TAPs are required to show compliance with the Washington TAP program pursuant to WAC 173-460. Ecology has established a de minimis threshold, SQER, and ASIL for each listed TAP. If the total project-related TAP emissions increase exceeds its respective SQER, further determination of compliance with the ASIL (i.e., dispersion modeling) is required. TAP emission calculations for the projects are described in Section 3 of this application. Specifically, Table 3-2 compares project-related

[4] 40 CFR 63.11193 and 63.11194.

[5] The boiler will also fire natural gas, which is categorized as a *gaseous fuel*. Pursuant to 40 CFR 63.11237, gaseous fuels do not trigger requirements under this subpart.

[6] If MLI implements an oxygen trim system that maintains an optimum air-to-fuel ratio, then a 5-year tune-up is required (as opposed to a biennial tune-up).

increases of each TAP to the corresponding de minimis threshold and SQER. As demonstrated by this table, only NO_2 emissions from the project exceed the SQER and trigger dispersion modeling requirements.

MLI prepared a modeling analysis using AERSCREEN to demonstrate that project impacts of NO_2 do not exceed the ASIL. The modeling methodology and detailed results are presented in Section 6 of this application. Detailed emission calculations are included in Appendix C and modeling files are included as Appendix F.

4.7.2. Other Washington Regulatory Requirements

The proposed upgrade project is subject to various regulations established by WAC 173-400-040 (General Standards for Maximum Emissions), WAC 173-400-050 (Emission Standards for Combustion and Incineration Units), and WAC 173-400-060 (Emission Standards for General Process Units). Emission units associated with the proposed project will satisfy all applicable regulations established by the WAC. Furthermore, the post-project facility will comply with all relevant standards of the WAC.

5. BACT/TBACT EVALUATION

Under WAC 173-400-113, Ecology requires new and modified sources to implement BACT for all pollutants not previously emitted or for those emissions that are projected to increase as a result of the new source or modification. Similarly, WAC 173-460-060 requires new and modified sources to install and operate BACT for project-related emissions of TAPs (tBACT).

The upgrade project proposes emission increases from the new boiler (Boiler #2) and new piping components. As shown in Table 3-1 of this application, only project-related emissions of NO_x and $PM_{2.5}$ exceed the corresponding pollutant-specific NSR exemption thresholds established by WAC 173-400-110(5). Furthermore, as depicted in Table 3-2, project-related emissions of benzene, formaldehyde, acrolein, NO_2, and CO exceed the de minimis thresholds established by 173-460-150. Therefore, the BACT/tBACT evaluation presented in this application is limited to these aforementioned pollutants, which are each associated with the operation of Boiler #2.

Section 5.3 of this application presents the BACT evaluation for $PM_{2.5}$ emissions from Boiler #2. As discussed with Ecology during the June 15, 2018 project kickoff meeting, CO emissions from a combustion source are inextricably linked to NO_x/NO_2 emissions. Therefore, Section 5.4 of this application, which presents the BACT/tBACT evaluation for NO_x/NO_2 emissions from Boiler #2, also discusses CO emissions. Lastly, Section 5.5 contains a qualitative tBACT evaluation for organic TAP (i.e., benzene, formaldehyde, acrolein) emissions from the proposed boiler.

As described in Section 7, MLI is requesting a redistribution of the existing methanol limits between fugitives and the flare. Although MLI's redistribution strategy proposes an increase in the permitted annual methanol limit for the flare, this request does not represent a project-related emissions increase. Rather, based on the results of flare inlet testing and an estimated control efficiency, the current permit limit for methanol does not adequately represent the worst-case flare venting rates at the current production limit for the Moses Lake facility. In a letter to Ecology dated August 29, 2008, MLI requested an increase in the flare's TMA emission limit to better represent source test results for TMA and the maximum TMAC production rate. This request was approved by Ecology and the permit limit was updated. However, a commensurate change to the methanol emission limit was not requested at the time.

As MLI's proposed upgrade project does not involve a TMAC production increase or a change to the maximum venting rate to the flare, the requested increase to the flare's methanol emission limit is unrelated to the project and does not trigger tBACT requirements. In fact, MLI expects the actual venting rate to the flare (and associated emissions) to decrease as a result of the process upgrades, which include improvements to the vent condenser systems. Furthermore, the net effect of MLI's redistribution strategy will result in a reduction in the permitted facility-wide annual methanol emission rate established by Approval Order No. 16AQ-E022.

5.1. INTRODUCTION TO BACT/TBACT METHODOLOGY

Although MLI's project does not trigger the federal BACT requirement established by 40 CFR 52.21 for PSD permitting actions, the general methodology used for a PSD BACT evaluation is generally applied to the minor NSR BACT/tBACT required for MLI's upgrade project. Unless otherwise noted, the following methodology is used as a guide for determining BACT/tBACT for project-related emissions increases.

In accordance with EPA's guidance, BACT/tBACT is determined on a pollutant-by-pollutant basis and covers new or modified emission units associated with a project that have net emission increases of the pollutants for which there is a project-wide significant net emission increase.[7] Consistent with the approach used by EPA and Ecology for other permitted projects, a "top-down" BACT/tBACT analysis organized by pollutant and by emissions source category is presented in the following sections of the application.

Although inherently lower emitting processes should be considered in a BACT/tBACT analysis, applicants are not required to alter the design of the main production processes at the proposed source based on BACT/tBACT requirements. Lower-emitting processes are only considered to be available if they are designed to manufacture identical or similar products from identical or similar raw materials or fuels. The applicant describes the inherent aspects of the proposed design that define the "source," and given these design constraints (e.g., the use of both natural gas and the co-product methanol stream as fuel for Boiler #2), BACT/tBACT is determined for the source in question on a case-by-case basis.

5.2. OVERVIEW OF 5-STEP BACT/TBACT EVALUATION PROCESS

Consistent with EPA's BACT guidance, BACT/tBACT for the proposed upgrade project has been evaluated via a "top-down" approach. Under this identified top-down approach, the most stringent control available for a similar or identical source or source category is identified. This control option is used to establish the BACT/tBACT emission limitation unless the applicant can demonstrate (and the permitting authority agrees) that it is not "achievable" due to technical infeasibility or cost-ineffectiveness or other adverse environmental or energy consequences of implementing the technology. If the top control alternative is eliminated, then the next most stringent level of control is evaluated. This process continues until the control option under consideration cannot be eliminated by any source specific adverse environmental, energy, or economic impacts.

5.2.1. BACT/tBACT Step 1 - Identify All Control Technologies

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical infeasibility and cost-ineffectiveness, or environmental and energy impacts, all control technologies with potential application to the emission unit under review should be identified.

5.2.2. BACT/tBACT Step 2 - Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling pollutant emissions from the source in question. An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology is only considered available if it has reached the licensing and commercial sales phase of development. Control technologies in the R&D and pilot scale phases are not considered available. An available control technology is considered applicable if it has been permitted or actually implemented by a similar source. Decisions about technical

[7] For MLI's upgrade project, which triggers minor NSR permitting requirements, the NSR exemption thresholds established by WAC 173-400-110(5) and the de minimis TAP thresholds established by WAC 173-460-150 are used in lieu of the PSD Significant Emission Rates (SERs) to determine the scope of the required BACT/tBACT evaluation.

feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative.

5.2.3. BACT/tBACT Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

5.2.4. BACT/tBACT Step 4 - Evaluate Most Effective Controls and Document Results

After identifying available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration, then it is selected as BACT/tBACT. Alternatively, if adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until an achievable control technology is identified.

5.2.5. BACT/tBACT Step 5 - Select BACT

In the final step, one pollutant specific control option establishes BACT/tBACT for each source of emissions under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT/tBACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT/tBACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT/tBACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

5.3. BOILER #2 BACT EVALUATION FOR $PM_{2.5}$ EMISSIONS

5.3.1. Step 1 – Identify All Control Technologies

The proposed 16.7 MMBtu/hr Boiler #2 generates $PM_{2.5}$ emissions by combusting either natural gas or methanol co-product. Although subject to NSPS Subpart Dc, the $PM_{2.5}$ limit of this subpart does not apply to Boiler #2 because the unit's rated capacity is below 30 MMBtu/hr. On the other hand, NESHAP Subpart JJJJJJ establishes a filterable PM limit of 0.03 lb/MMBtu for a new unit combusting liquid fuels, including the proposed methanol fuel stream. Based on the results of source testing conducted by MLI on the facility's existing boiler (Boiler #1), which also fires both natural gas and methanol co-product, filterable PM emissions from Boiler #1 during methanol fuel combustion are in compliance with this limit.[8] Given the compliance margin, EPA granted MLI a waiver from the follow-up testing requirements of NESHAP Subpart JJJJJJ. Considering the operational similarities, MLI expects the PM emissions profile for Boiler #2 to be very similar to Boiler #1.

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[8] According to footnote c to Table 1.4-2 of EPA's AP-42, all PM generated by the combustion of natural gas is assumed to be less than 1.0 micrometer in diameter. Therefore, $PM_{2.5}$ emissions equal PM_{10} and total PM (filterable and condensable) emissions.

Based on a review of similar sources in the RACT/BACT/LAER Clearinghouse (RBLC), no comparable facilities or facilities with similar process types were identified as using any type of add-on control device for PM emissions. This finding is important and bolsters the conclusion that BACT determinations for gas- and clean liquid fuel-fired boilers should be limited to emission limits based on good operating and combustion practices without the use of add-on control devices. Consistent with MLI's review of technical literature, past control technology determinations, and generally available technologies and practices, available PM control options for Boiler #2 are limited to good combustion and operating practices.

5.3.2. Step 2 – Eliminate Technically Infeasible Options

As described in Step 1, only the following control option is carried through to Step 3:

Good Design and Operating Practices

Good design and operating practices (including good combustion practices), which may be implemented to increase production efficiency and maintain optimum burner operation thus minimizing PM emissions, are considered to be technically feasible for the proposed boiler.

5.3.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

As only a single control option remains for Boiler #2 (i.e., good design and operating practices), which has an undefined control efficiency, a ranking is not provided for the boiler.

5.3.4. Step 4 - Evaluate Most Effective Controls and Document Results

Good Design and Operating Practices

As no add-on control technologies were determined to be technically feasible for the control of PM emissions from Boiler #2, the only remaining control option is good combustion design and operating practices. A properly operated and maintained combustion source minimizes PM formation by ensuring that the combustion temperature and oxygen availability are adequate for proper combustion.

5.3.5. Step 5 - Select BACT

MLI proposes to operate Boiler #2 in accordance with good combustion and operating practices to achieve compliance with the following PM BACT limits.

- Methanol co-product combustion: 0.03 lb/MMBtu (applies to filterable PM only)
- Natural gas combustion: 0.007 lb/MMBtu (applies to filterable and condensable $PM_{2.5}$ emissions)

The proposed BACT limit associated with the combustion of methanol in Boiler #2 corresponds to the regulatory limit under NESHAP Subpart JJJJJJ. The proposed BACT limit for natural gas combustion corresponds to the AP-42 emission factor for total PM from Table 1.4-2.

To ensure compliance with the proposed BACT limits, MLI will operate the boiler in accordance with manufacturer recommendations. Furthermore, MLI will either conduct source testing in accordance with NESHAP Subpart JJJJJJ or obtain a waiver from PM source testing requirements from EPA based on the previous testing conducted on Boiler #1 while combusting the methanol co-product stream.

5.4. BOILER #2 BACT/TBACT EVALUATION FOR NO_X/NO_2 EMISSIONS[9]

5.4.1. Step 1 – Identify All Control Technologies

In combustion-related operations, NO_x is typically formed by two fundamentally different main mechanisms: fuel NO_x, and thermal NO_x. "Fuel NO_x" forms when the fuel bound nitrogen compounds are converted into nitrogen oxides. The amount of fuel bound nitrogen converted to fuel NO_x depends largely upon the fuel type, nitrogen content of the fuel, air supply, and design of combustion chamber (including combustion temperature). NO_x formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." Temperature is the most important factor, and at flame temperatures above 2,200 °F, thermal NO_x formation increases exponentially.[10] During Boiler #2's combustion of natural gas, thermal NO_x is the primary NO_x generating mechanism applicable to the proposed project. However, given the TMA concentration in the methanol co-product stream, both thermal NO_x and fuel NO_x is expected from the combustion of methanol. The guarantee provided by Cole Industrial, the boiler vendor, for emissions from Boiler #2 while combusting the methanol co-product stream accounts for both thermal NO_x and NO_x from fuel-bound nitrogen.[11]

NO_x reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_x formation (reducing peak flame temperature) or introduce inerts (e.g., combustion products) that limit initial NO_x formation, or both. Several post-combustion NO_x control technologies that employ various strategies to chemically reduce NO_x to elemental nitrogen (N_2) with or without the use of a catalyst are also potentially applicable to reduce NO_x emissions from combustion processes.

The following control technology options are potentially available for the control of NO_x emissions from the proposed boiler, in addition to good combustion and operating practices. The specifically available options for a given category of combustion equipment are identified in subsequent sections.

Combustion control options include:

- Good combustion and operating practices
- Flue gas recirculation (FGR)
- Enhanced FGR

Post-combustion control options include:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

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[9] Section 5.4 documents the BACT evaluation for both NO_x emissions, which are regulated under WAC 173-400, and NO_2 emissions, which are regulated under WAC 173-460. Since the evaluations are identical, and associated cost calculations assume that 100% of NO_x from Boiler #2 is in the form of NO_2 for conservatism, the remainder of this section refers only to NO_x for the sake of simplicity.

[10] Kraft, D.L. Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge. Barberton, OH: Babcock & Wilcox. September 1998. http://www.babcock.com/library/Documents/br-1661.pdf.

[11] To develop the emission guarantees for Boiler #2, MLI provided Cole Industrial with information about the methanol co-product stream, including anticipated TMA concentrations. As such, any impact to NO_x emissions from Boiler #2 associated with trace TMA concentrations in the methanol co-product stream was considered by Cole Industrial in the development of the emission guarantees.

Each control technology is described in detail below.

Selective Catalytic Reduction

SCR is a post-combustion gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, ammonia and NO_x react to form elemental nitrogen and water. The primary chemical reactions can be expressed as follows:

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$4\ NH_3 + 2\ NO_2 + 2\ O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

When operated within the optimum temperature range of 575 to 750°F, the reaction can result in removal efficiencies between 70 and 90%.[12] Operation outside the optimum temperature range can result in increased ammonia slip or increased NO_x emissions. SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50°F), although fluctuation in exhaust gas temperature reduces removal efficiency slightly by disturbing the kinetics (speed) of the NO_x-removal reaction.

Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_x control technology based on the reaction of urea or ammonia with NO_x. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_x to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$

$$4\ NH_3 + 6NO \rightarrow 5\ N_2 + 6\ H_2O$$

Typical removal efficiencies for SNCR range from 30 to 65%.[13] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F.[14] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_x.

Good Combustion and Operating Practices

The formation of NO_x is minimized by proper furnace/combustion chamber design and operation. Generally, emissions are minimized when the furnace temperature is kept at the lower end of the desired range and when the distribution of air at the air and fuel injection zones is controlled. Ideally, maintaining a low-oxygen condition near fuel injection points approaches an off-stoichiometric staged combustion process.

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[12] EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual Section 4-2 Chapter 2, 6th edition*. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.

[13] EPA, Office of Air Quality Planning and Standards *OAQPS Control Cost Manual Section 4-2 Chapter 1*, 6th edition. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.

[14] EPA, Clean Air Technology Center. *Nitrogen Oxides (NO_X), Why and How They Are Controlled*. Research Triangle Park, North Carolina. p. 18, EPA-456/F-99-006R, November 1999.

A certain amount of air is required to provide sufficient oxygen to burn all of the fuel. However, under some conditions, excess air may contribute to increased NO_x emissions in two ways: 1) Excess air effectively increases the amount of air that must be heated, resulting in decreased fuel efficiency and higher NO_x emissions, and 2) Excess air provides greater amounts of oxygen in the combustion zone that will lead to greater amounts of thermal NO_x formation. At the same time, depending on operating conditions, the use of excess air may also reduce peak flame temperature and the associated thermal NO_x emissions. By minimizing the amount of air used in the combustion process while maintaining proper furnace operation and the appropriate peak flame temperature, the formation of NO_x can be reduced.

Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) as applied to boilers involves recirculating a small portion of combustion unit's exhaust gas to the combustion air stream. The increased flow with gas recirculation can provide increased turbulence, allowing higher fuel combustion efficiency with lowered total excess air. This, in effect, reduces the formation of NO_x because less oxygen is available compared to ambient air and the driving force to form nitrogen oxides is reduced.

Enhanced FGR

In addition to the standard FGR control option, the boiler vendor (Cole Industrial) has also provided specifications for an enhanced FGR option that would further reduce NO_x emissions during the combustion of natural gas by increasing the FGR system's recirculation rate. However, according to Cole Industrial, this option further reduces combustion efficiency and makes the boiler's operation more difficult to control. Furthermore, the operating conditions associated with the enhanced FGR option may result in additional unknown effects to the destruction efficiency of methanol and TMA in the boiler.

5.4.2. Step 2 – Eliminate Technically Infeasible Control Options

The technical feasibility of each of the control technologies identified for Boiler #2 is described below.

Selective Catalytic Reduction

For Boiler #2, the SCR process requires temperatures of 575 to 750°F to achieve high conversion rates for NO_x, although the optimum temperature for conversion is estimated to be 700°F. [15] At 417°F (the estimated exhaust temperature of Boiler #2 based on the source test results of Boiler #1), the exhaust gas falls just below this range. According to EPA's control technology literature, SCR is considered a feasible add-on control device for gas-fired combustion units rated at greater than 50 MMBtu/hr.[16] Even though Boiler #2 is rated at 16.7 MMBtu/hr, MLI has considered SCR in subsequent steps of this BACT analysis for conservatism.

Selective Non-Catalytic Reduction

The SNCR oxidation process requires temperatures of 1,600 to 2,100°F to achieve high conversion rates for NO_x.[17] At 417°F, the exhaust gas from Boiler #2 would need to be preheated considerably in order to provide effective NO_x control through SNCR, but preheating is considered technically feasible. According to EPA's control

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[15] EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual Section 4-2 Chapter 2, 6th edition*. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.

[16] *Ibid.*

[17] EPA, *Air Pollution Control Technology Fact Sheet – Selective Non-Catalytic Reduction*. EPA-452/F-03-031.

technology literature, SNCR is considered to be feasible for implementation on combustion units ranging in size from 50 to 6,000 MMBtu/hr.[18] Even though Boiler #2 is rated at 16.7 MMBtu/hr, MLI has considered SNCR in subsequent steps of this BACT analysis for conservatism.

Flue Gas Recirculation

FGR reroutes a portion of the flue gas back into the combustion zone to reduce the amount of thermal NO_x formed. MLI's proposed boiler will be equipped with FGR to reduce NO_x emissions, and therefore, it is considered a technically feasible control option and represents the base case for this BACT evaluation.

Enhanced FGR

Similar to FGR, enhanced FGR reroutes a portion of the flue gas back into the combustion zone to reduce the amount of thermal NO_x formed; however, enhanced FGR will have a higher recirculation flow rate and result in increased energy demands and operational instability relative to the standard FGR option. Enhanced FGR is considered a technically feasible control option.

Good Combustion and Operating Practices

For Boiler #2, good combustion and operating practices implemented to minimize NO_x formation are considered technically feasible.

5.4.3. Step 3 – Rank Remaining Control Options by Effectiveness

SCR, SNCR, FGR, enhanced FGR, and good combustion and operating practices represent the available and technically feasible control technologies for Boiler #2. These options are ranked in order of control efficiency in Table 5-1.

[18] *Ibid.*

Table 5-1. Remaining Control Technologies Ranked by Effectiveness for NO_x

Emission Unit	Control Technology	Control Efficiency
Boiler #2	Selective Catalytic Reduction (SCR)	90%
	Enhanced FGR	70%[19]
	Selective Non-Catalytic Reduction (SNCR)	65%
	Flue Gas Recirculation	Undefined (Base case)
	Good Combustion and Operating Practices	Undefined (Base case)

5.4.4. Step 4 – Evaluate Most Effective Controls and Document Results

The following discussion documents the economic and environmental impacts of the technically feasible control options for Boiler #2, starting with the most effective control option.

Selective Catalytic Reduction

MLI evaluated the cost of implementing SCR technology using EPA's *SCR Cost Calculation Spreadsheet*.[20] By considering a 90% removal efficiency and assuming that the SCR control system can be effectively implemented at the exhaust temperature of Boiler #2 without supplemental heating, control costs are approximately $12,695 per ton of NO_x removed. However, in order to achieve the design removal efficiency of the SCR system, a preheater would be required to bring the exhaust stream to the optimum reaction temperature (700°F) prior to routing the exhaust through the SCR system. The natural gas usage associated with this preheater would increase control costs to approximately $15,835 per ton of NO_x removed without accounting for the cost of the preheater itself. Accordingly, the implementation of SCR technology to control NO_x emissions from Boiler #2 is considered economically ineffective and is eliminated from further consideration in this BACT evaluation. The detailed cost calculations for a SCR system are presented in Appendix D.

Selective Non-Catalytic Reduction

The implementation of SNCR technology requires a similar capital investment to the implementation of a SCR system. Although a catalyst is not required for SNCR, the additional energy costs of increasing the exhaust temperature to 1,600°F (i.e., the minimum operating temperature for a SNCR system) make SNCR technology

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[19] This control efficiency is based on Cole Industrial's 9 ppm NO_x guarantee for the enhanced FGR system relative to the 30 ppm NO_x guarantee for the base case FGR option. These guarantees apply to the combustion of natural gas only.

[20] The *SCR Cost Calculation Spreadsheet* was updated on December 5, 2016 and can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

more costly than a SCR system. Therefore, the control costs for SNCR are expected to be higher than the control costs calculated by MLI for SCR, and the implementation of SNCR technology to control NO_x emissions from Boiler #2 is considered economically ineffective. As such, SNCR technology is eliminated from further consideration in this BACT evaluation.

Enhanced FGR

Cole Industrial provided design information to MLI for an enhanced FGR system that would reduce NO_x emissions from Boiler #2 during natural gas combustion. According to Cole Industrial, this option would only be used during the combustion of natural gas. This enhanced FGR system would reduce maximum NO_x concentrations in the boiler exhaust from 30 ppmvd NO_x @ 3% O_2 to 9 ppmvd NO_x @ 3% O_2. However, this option would incur several additional costs.

Specifically, the capital and installation costs of the enhanced FGR system would increase relative to the base case FGR system. Furthermore, rather than tuning the boiler annually, Cole recommends quarterly tune-ups based on their operating experience with this enhanced system. These additional tune-ups increase the maintenance costs of the enhanced system. Additionally, in order to increase the FGR flow rate to accomplish this NO_x reduction during natural gas firing scenarios, a larger blower would be required.

To calculate the cumulative control costs of these changes, MLI conservatively assumes that natural gas will be fired in Boiler #2 at the unit's capacity for 75% of the year.[21] The result of this evaluation indicates that control costs for the enhanced FGR system would total over $19,000 per ton of NO_x removed. Accordingly, the implementation of enhanced FGR technology to control NO_x emissions from Boiler #2 is considered economically ineffective and is eliminated from further consideration in this BACT evaluation. The detailed cost calculations for the enhanced FGR system are presented in Appendix D.

Flue Gas Recirculation

MLI is proposing to install a boiler with low NO_x burners and FGR as the base case to minimize NO_x emissions. Therefore, economic, energy, and environmental considerations of the FGR system are not discussed further.

Good Combustion and Operating Practices

MLI is proposing to operate Boiler #2 in accordance with good combustion and operating practices as the base case. Therefore, economic, energy, and environmental considerations are not discussed further.

5.4.5. Step 5 – Select BACT

The proposed boiler is subject to NSPS Subpart Dc and NESHAP Subpart JJJJJJ; however, these regulations do not establish limits for NO_x emissions. Therefore, MLI's proposed BACT determinations are based on the Cole Industrial guarantees for the base case identified in this BACT evaluation. As described previously, these NO_x guarantees are intrinsically linked to CO emissions. Therefore, MLI proposes the following fuel-specific BACT limits for both NO_x and CO emissions:

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[21] Although MLI is proposing an operational limit on the use of methanol in Boiler #2 (1,201,000 gallons per year) that corresponds to 50% of the unit's annual rated heat input capacity, a higher natural gas usage rate corresponds to increased emission reductions from the enhanced FGR system and lower control costs. Therefore, to conservatively calculate these control costs, MLI assumed that natural gas will be fired in the boiler at the unit's capacity for 75% of the year.

- Methanol co-product combustion: 112 ppmvd NO_x @ 3% O_2 and 100 ppmvd CO @ 3% O_2 (i.e., 0.133 lb/MMBtu NO_x and 0.072 lb/MMBtu CO)
- Natural gas combustion: 30 ppmvd NO_x @ 3% O_2 and 50 ppmvd CO @ 3% O_2 (i.e., 0.036 lb/MMBtu NO_x and 0.036 lb/MMBtu CO)

In order to satisfy these limits, MLI is proposing to install a boiler with low NO_x burners and FGR, and to operate the unit in accordance with good combustion and operating practices including following manufacturer recommendations for operating and maintaining the boiler.

5.5. BOILER #2 TBACT EVALUATION FOR ORGANIC TAP EMISSIONS

As explained earlier in this section, project-related emissions of benzene, formaldehyde, and acrolein exceed the de minimis thresholds established by 173-460-150. In accordance with Ecology's request, emission estimates for these TAPs are based on the Ventura County Air Pollution Control District's emission factors for natural gas combustion (AB 2588). There are no NSPS or NESHAP standards that restrict VOC emissions or emissions of specific organic TAPs from the proposed Boiler #2, which would serve as a baseline for this BACT determination. Based on a review of RBLC entries for similar systems, the VOC control options are limited to oxidation catalysts and good combustion practices. However, as discussed with Ecology during the June 15, 2018 kickoff meeting, the costs of implementing catalytic oxidation technology on a natural gas combustion source is not cost effective for the control of VOC emissions. These control costs would be much higher for the TAPs that trigger tBACT, based on comparable equipment and operating costs and lower emission rates for the specific TAPs under consideration. Therefore, add-on control technologies are considered economically ineffective, and MLI proposes good combustion and operating practices to minimize the formation of these TAPs in the boiler exhaust stream.

As demonstrated by Table 3-2, with the exception of NO_2 emissions, project-related emission increases of TAPs subject to regulation under WAC 173-460 are below the corresponding SQERs. Therefore, only NO_2 emissions trigger dispersion modeling requirements to demonstrate compliance with the ASIL. All project-related increases of potential NO_2 emissions are associated with the operation of Boiler #2. The maximum hourly NO_2 emission rate for Boiler #2, which corresponds to the combustion of the methanol co-product fuel stream at the boiler's maximum heat input capacity, is used as the basis for this modeling analysis. Details regarding the model selection, inputs, and results are provided in the following sections.

6.1. SCREENING METHODOLOGY

6.1.1. Model Selection

This analysis uses the U.S. EPA preferred model for screening assessments, AERSCREEN, for evaluating ambient air impacts from potential emission increases associated with the proposed project. The result from an AERSCREEN model is a predicted ambient concentration that represents a conservative estimate of the maximum post-project ambient concentration at the modeled (maximum) emission rate.

6.1.2. Modeling Parameters

NO_2 emissions from Boiler #2 will be routed through a new stack to be constructed at the Moses Lake facility as part of the proposed project. The modeling parameters are determined based on the design of the boiler and associated stack. Table 6-1 summarizes the model input parameters for the exhaust stream. Since there is only one point source associated with project-related increases of NO_2 emissions, a nominal emission rate of 1 gram per second (g/s) is entered as the AERSCEEN input value. The model result is then scaled by the maximum NO_2 emission rate from Boiler #2 to determine the maximum ambient impact of the project.

Table 6-1. Source Parameters

Source ID	Modeled Emission Rate (g/s)	Source Elevation [a] (m)	Stack Height [b] (m)	Stack Diameter [b] (m)	Exhaust Temperature [c] (K)	Exhaust Velocity [d] (m/s)	Distance to Fenceline [e] (m)
Point	1	352.04	18.90	0.71	487.04	4.78	62

[a] Approximate source elevation of 1155 ft from MLI's site plan.

[b] MLI's design for the Boiler #2 stack corresponds to a stack height of 62 feet and a stack diameter of 28 inches.

[c] The stack temperature is estimated based on the average result of the 2017 source test for Boiler #1. Since Boiler #2 will be equipped with a FGR system, which will reduce the combustion temperature relative to Boiler #1, this exhaust temperature is conservative.

[d] The stack flow rate is based on the heat input capacity of Boiler #2 at 100% firing rate (16.7 MMBtu/hr), as provided by Cole Industrial (the boiler vendor). This heat input capacity is scaled by the F-factor for natural gas from EPA Method 19 (8,710 dscf/MMBtu) and converted to acfm based on the anticipated stack temperature. This calculation assumes the exhaust is at ambient pressure and at 0% O_2 for conservatism. The resulting volumetric flow rate is then divided by the stack diameter to determine the exit velocity.

[e] The 'distance to fenceline' refers to the shortest distance from the proposed Boiler #2 stack location to the Moses Lake facility's fenceline, as depicted by the site plan presented in Appendix B of this application.

6.1.3. Meteorological Data

The MAKEMET processor in AERSCREEN generates meteorological conditions based on user-specified surface characteristics, ambient extreme temperatures, minimum wind speed, and anemometer height. For this project, the suggested default values of MAKEMET are used for the minimum wind speed (0.5 m/s) and the anemometer height (10 meters). The maximum and minimum ambient temperatures are set to the daily extremes based on 2016 observations at Moses Lake (station name KMWH). Rural land use option and average climate profile for cultivated land are used for MLI's facility.

6.1.4. Building Downwash

The purpose of a building downwash analysis is to determine whether the plume discharged from a stack will become caught in the turbulent wake of a building (or other structure). Wind blowing near a building creates zones of turbulence that are greater than in open air, resulting in plume downwash, which can result in elevated ground-level concentrations. Building downwash is considered for screening analyses of point sources to accurately represent the dispersion of emissions from the modeled stack.

The AERSCREEN program can compute downwash effects for one or multiple buildings. The Boiler #2 stack will be located nearly equidistant to a number of facility buildings. Each of the buildings are of similar structural size, making it difficult to establish which structure will be dominant in a downwash analysis. As a refined approach, the nearby buildings and boiler stack location were compiled into a BPIPPRM input file to allow BPIPPRM to determine the dominant structure directly. As indicated by the AERSCREEN output file, the nearby structures were of insufficient size and not in close enough proximity to the new boiler stack to cause downwash effects. The building dimensions were determined based on MLI's site plan, which is provided as Appendix B. Electronic versions of the modeling files, including the BPIP input and setup files, are included as Appendix F.

6.2. TAP SCREENING RESULTS

The concentration output from AERSCREEN is the maximum concentration from modeling the unit emission rate of 1 g/s. The maximum concentration is then multiplied by the maximum expected NO_2 emission rate from Boiler #2 to compare with the corresponding ASIL. Electronic copies of all AERSCREEN inputs and outputs are provided in Appendix F.

Table 6-2 demonstrates that the result of the screening model is below the ASIL for NO_2. Therefore, the ambient NO_2 concentrations resulting from the proposed project are considered acceptable under WAC 173-460 and no further analysis is required.

Table 6-2. Screening Result for NO_2 Emissions from Boiler #2

Pollutant	Maximum Emission Rate [b] (g/s)	Unit Emission Rate Modeled Concentration (μg/m³)	Model Averaging Period	Scaled Concentration (μg/m³)	ASIL (μg/m³)	ASIL Averaging period
NO_2	0.23	42.75	1-hr	9.63	470	1-hr

[a] The maximum NO_2 emission rate for Boiler #2 (2.22 lbs/hr; 0.28 g/s) corresponds to the boiler vendor's guarantee (112 ppmvd NO_x @ 3% O_2) for the combustion of the methanol co-product fuel stream at the boiler's maximum heat input capacity (16.7 MMBtu/hr). For conservatism, all NO_x is assumed to be NO_2.

6.3. NAAQS SCREENING RESULTS

As requested by Ecology in a July 26, 2018 email from Jenny Filipy to Pat Blau, the following table compares the results of the AERSCREEN modeling evaluation for the new boiler to the relevant National Ambient Air Quality Standards (NAAQS) for NO_2 and $PM_{2.5}$. This evaluation assesses the project's compliance with the NAAQS by assuming that project-related impacts coupled with a representative background concentration for the area yield a reasonable estimate of total post-project pollutant concentrations in the area around MLI's facility. Per Ecology's guidance, ambient pollutant concentration data published by Washington State University's Northwest International Air Quality Environmental Science and Technology Consortium (NW AIRQUEST) was used to determine representative background concentrations for NO_2 and $PM_{2.5}$ (based on data collected for 2009 through 2011).

As discussed in Section 6.2, the output from AERSCREEN represents the maximum concentrations from modeling the unit emission rate of 1 g/s at various averaging periods. The maximum concentration for a given averaging period is then multiplied by the maximum expected NO_2 or $PM_{2.5}$ emission rate from Boiler #2 to estimate project-related impacts. For conservatism, the new boiler's worst-case short-term emission rate for each pollutant was used as the basis for this assessment, regardless of the modeled averaging period. By adding a representative background concentration to these scaled modeled concentrations, compliance with each NAAQS for NO_2 and $PM_{2.5}$ is demonstrated. Electronic copies of all AERSCREEN inputs and outputs are provided in Appendix F.

Table 6-3 demonstrates that post-project impacts from the Moses Lake facility will maintain compliance with the NAAQS for NO_2 and $PM_{2.5}$. Therefore, the ambient NO_2 and $PM_{2.5}$ concentrations resulting from the proposed project demonstrate compliance with the ambient air quality standards established under WAC 173-476 and no further analysis is required.

Table 6-3. Simplified NAAQS Compliance Demonstration for Emissions from Boiler #2

Pollutant	Modeled Averaging Period	Modeled Concentration - Unit Emission Rate (μg/m³)	Modeled Concentration – Scaled Emission Rate[a] (μg/m³)	Represent-ative Background[b] (μg/m³)	Total Impact (μg/m³)	NAAQS (μg/m³)	In Comp-liance with NAAQS?
NO_2	1-hour	42.75	11.98	16.00	27.98	188	Yes
	annual	4.275	1.20	2.82	4.02	100	Yes
$PM_{2.5}$	24-hour	25.65	0.40	14	14.40	35	Yes
	annual	4.275	0.07	5.3	5.37	12	Yes

[a] The modeled results for the unit emission rate (1 g/s) were scaled by the appropriate projected emission rate for the new boiler to assess compliance with the NAAQS. Projected Boiler Emission Rates: 2.22 lb/hr (0.28 g/s) NO_2; 0.12 lb/hr (0.02 g/s) $PM_{2.5}$.

[b] Per Ecology's suggestion, as communicated in a July 26, 2018 email from Jenny Filipy (Ecology) to Pat Blau (MLI), the following website was used to determine representative background concentrations for NO_2 and $PM_{2.5}$: http://lar.wsu.edu/nw-airquest/lookup.html
These results are based on the following facility location, expressed in latitude/longitude: 47.2051947, -119.2909225
Background values expressed in ppb were converted to ug/m3 by multiplying the concentration in ppb by the molecular weight and then dividing the result by (0.02447*1000).

7. REQUESTED PERMIT CHANGES

This section explains the basis for requested changes to existing emission limits established by MLI's current air permit. The proposed permit limits are further documented in Section C5 of Appendix C.

- As discussed with Ecology during the June 15, 2018 project kickoff meeting, MLI requests that the total TAPs limits be removed from the permit as there is no regulatory basis for limiting total TAP emissions. Furthermore, MLI would be supportive of Ecology removing TMA limits from the permit, based on the fact that TMA is no longer regulated as a TAP under WAC 173-460. However, TMA calculations and proposed limits are included in Appendix C to provide a comprehensive emissions profile for the project.
- MLI requests that the fugitive emission limit for methanol be revised based on the methodology described in Section C3 of Appendix C. This request involves reducing the fugitive methanol limit of the current permit based on recent emission calculations for the Moses Lake facility along with conservative scaling factors to determine potential emissions from actual reported emissions. The proposed methanol fugitive limit also accounts for emissions from new piping components associated with the upgrade project. MLI's proposed limit represents a decrease of approximately 3,500 lbs/yr relative to the current permit limit for fugitive methanol emissions.
- In reviewing the historical permit limit changes associated with the flare, it is noted that in 2008, Ecology adjusted the flare limit for TMA emissions upwards from 496 to 5,000 lbs/yr to account for errors or items not considered in the original permitting. At the time, source testing procedures had not adequately quantified methanol emissions and hence, a commensurate change in the methanol limit was not implemented. More recent testing indicates that an adjustment in the flare methanol limit is also appropriate. Accordingly, MLI requests that 1,600 lbs/yr of methanol that is currently allocated to the facility's fugitive sources be reallocated to the flare. MLI would like to emphasize that vents to the flare are not expected to increase as a result of the proposed TMAC Product Quality/Emissions Upgrade project for the Moses Lake facility. Given the process improvements, particularly with respect to the vent condenser upgrades, cross-over line capability, and increased reactor residence time as described in Section 2 of this application, MLI expects actual vents to the flare (at the maximum permitted production rate) to decrease as a result of the project. The net effect of the proposed methanol emission limit redistribution strategy is a decrease in facility-wide permitted annual methanol emissions relative to the emission limit currently established by Approval Order No. 16AQ-E022.
- MLI proposes that 100 lbs/yr of TMA emissions currently allocated to the flare be reallocated to Boiler #2 to represent emission increases from the proposed project. Due to the process improvements associated with the proposed upgrade project, the actual flare venting rate is expected to decrease at the facility's maximum TMAC production rate. Consequently, even at the maximum anticipated TMAC production rate, MLI will be able to demonstrate compliance with this reduced TMA limit for the flare. This reallocation strategy ensures that facility-wide permitted TMA emissions do not increase as a result of the upgrade project relative to the emission limit currently established by Approval Order No. 16AQ-E022.

The following table presents the requested limits by unit and on a facility-wide basis following the proposed upgrade project. Proposed limits that represent changes to the emission limits established by Approval Order No. 16AQ-E022 are denoted in ***bold italicized font***. Additional details to support these proposed limits is provided in Appendix C.

Table 7-1. Proposed Permit Limits

Pollutant	Source					Units
	Boiler #1	Boiler #2	Flare	Fugitive	Total	
NO_x	7.5	***6.17***	6.99	--	***20.7***	tons/yr
CO	2.0	***4.0***	2.0	--	***8.0***	tons/yr
VOC (in actual weight)	1.79	***0.94***	6.49	12.52	***21.74***	tons/yr
TAPs (total)	--	--	--	--	--	--
Methanol	1,740	***1,000***	***3,022***	***8,095***	***13,857***	lbs/yr
TMA	20	***100***	***4,900***	3,000	8,020	lbs/yr

APPENDIX A: APPLICATION FORMS

Notice of Construction Application

A notice of construction permit is required before installing a new source of air pollution or modifying an existing source of air pollution. This application applies to facilities in Ecology's jurisdiction. Submit this application for review of your project. For general information about completing the application, refer to Ecology Forms ECY 070-410a-g, "Instructions for Ecology's Notice of Construction Application."

Ecology offers up to 2 hours of free pre-application help. We encourage you to schedule a pre-application meeting with the contact person specified for the location of your proposal (see below). For more help than the initial 2 free hours, submit Part 1 of the application and the application fee. You may schedule a meeting with us at any point in the process.

Completing the application, enclose it with a check for the initial fee and mail to:

WA Department of Ecology
Cashiering Unit
P.O. Box 47611
Olympia, WA 98504-7611

For Fiscal Office Use Only:
001-NSR-216-0299-000404

Check the box for the location of your proposal. For help, call the contact listed below.		
	Ecology Permitting Office	**Contact**
☐ **CRO**	**Chelan, Douglas, Kittitas, Klickitat, or Okanogan County** Ecology Central Regional Office – Air Quality Program	Lynnette Haller (509) 457-7126 lynnette.haller@ecy.wa.gov
☒ **ERO**	**Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Stevens, Walla Walla, or Whitman County** Ecology Eastern Regional Office – Air Quality Program	Jolaine Johnson (509) 329-3452 jolaine.johnson@ecy.wa.gov
☐ **NWRO**	**San Juan County** Ecology Northwest Regional Office – Air Quality Program	Dave Adler (425) 649-7267 david.adler@ecy.wa.gov
☐ **IND**	**Kraft and Sulfite Paper Mills and Aluminum Smelters** Ecology Industrial Section – Waste 2 Resources Program Permit manager: ______________________	James DeMay (360) 407-6868 james.demay@ecy.wa.gov
☐ **NWP**	**U.S. Department of Energy Hanford Reservation** Ecology Nuclear Waste Program	Phil Gent (509) 372-7983 phil.gent@ecy.wa.gov

To request ADA accommodation, call (360) 407-6800, 711 (relay service), or 877-833-6341 (TTY).

Notice of Construction Application

Check the box for the fee that applies to your application.

New project or equipment

☒	**$1,500: Basic project** initial fee covers up to 16 hours of review
☐	**$10,000: Complex project** initial fee covers up to 106 hours of review

Change to an existing permit or equipment

☐	**$200: Administrative or simple change** initial fee covers up to 3 hours of review Ecology may determine your change is complex during completeness review of your application. If your project is complex, you must pay the additional $675 before we will continue working on your application.
☒	**$875: Complex change** initial fee covers up to 10 hours of review
☐	**$350** flat fee: **Replace or alter control technology equipment** (WAC 173-400-114) Ecology will contact you if we determine your change belongs in another fee category. You must pay the fee associated with that category before we will continue working on your application.

Read each statement, then check the box next to it to acknowledge that you agree.

☒	The initial fee you submitted may not cover the cost of processing your application. Ecology will track the number of hours spent on your project. If the number of hours Ecology spends exceeds the hours included in your initial fee, Ecology will charge you $95 per hour for the extra time.
☒	You must include all information in this application. Ecology may not process your application if it does not include all the information requested.
☒	Submittal of this application allows Ecology staff to inspect your facility.

DEPARTMENT OF ECOLOGY
State of Washington

Notice of Construction Application

Part 1: General Information

I. Project, Facility, and Company Information

1. Project Name TMAC Product Quality/Emissions Upgrade and New Boiler #2	
2. Facility Name Moses Lake Industries	
3. Facility Street Address 8248 Randolph Road NE	
4. Facility Legal Description Section 27, Range 28E, Township 20N, Grant County, State of Washington	
5. Company Legal Name (if different than Facility Name)	
6. Company Mailing Address (street, city, state, zip) 8248 Randolph Road NE	

II. Contact Information and Certification

1. Facility Contact Name (who will be on-site) Patrick Blau	
2. Facility Contact Mailing Address (if different than Company Mailing Address)	
3. Facility Contact Phone Number 509-762-5336 x 236	4. Facility Contact Email pblau@mlindustries.com
5. Billing Contact Name (who should receive billing information) Patrick Blau	
6. Billing Contact Mailing Address (if different than Company Mailing Address)	
7. Billing Contact Phone Number	8. Billing Contact Email
9. Consultant Name (optional – if 3rd party hired to complete application) Back-up contact ONLY after first checking with Pat Blau: Maren Seibold	
10. Consultant Organization/Company Trinity Consultants	
11. Consultant Mailing Address (street, city, state, zip)	
12. Consultant Phone Number 859-341-8100 x 104	13.Consultant Email MSeibold@Trinityconsultants.com
14. Responsible Official Name and Title (person responsible for project policy or decision-making) Mike Tiffany, DP Operations Manager	
15. Responsible Official Mailing Address 8248 Randolph Road NE	
16. Responsible Official Phone 509-762-5336	17. Responsible Official Email mtiffany@mlindustries.com
18. Responsible Official Certification and Signature I certify that the information on this application is accurate and complete. Signature ______________________________ Date__________________	

Notice of Construction Application

Part 2: Technical Information

The Technical Information may be sent with this application to the Ecology Cashiering Unit, or may be sent directly to the appropriate Ecology office along with a copy of this application.

For all sections, check the box next to each item as you complete it.

III. Project Description

Attach the following to your application:

- ☒ Description of your proposed project (See Section 2 of NOC Application)
- ☒ Projected construction start and completion dates (See Section 2 of NOC Application)
- ☒ Operating schedule and production rates (See Section 2 of NOC Application)
- ☒ List of all major process equipment with manufacturer and maximum rated capacity (See Section 2 of Application)
- ☐ Process flow diagram with all emission points identified (Only new boiler added, does not change TMAC Process PFD)
- ☒ Plan view site map (See Appendix B of NOC Application)
- ☒ Manufacturer specification sheets for major process equipment components (See Appendix E of NOC Application)
- ☐ Manufacturer specification sheets for pollution control equipment (N/A; no add-on control equipment from project)
- ☒ Fuel specifications, including type, consumption (per hour and per year), and percent sulfur (See Appendix C of NOC Application)

IV. State Environmental Policy Act (SEPA) Compliance

Check the appropriate box below.

☐ SEPA review is complete.
Include a copy of the final SEPA checklist and SEPA determination (e.g., DNS, MDNS, EIS) with your application.

☒ SEPA review has not been conducted.

☒ If SEPA review will be conducted by another agency, list the agency. You must provide a copy of the final SEPA checklist and SEPA determination before Ecology will issue your permit.

Agency Reviewing SEPA:

Grant County

☐ If SEPA review will be conducted by Ecology, fill out a SEPA checklist and submit it with your application. You can find a SEPA checklist online at http://www.ecy.wa.gov/programs/sea/sepa/forms.htm.

Notice of Construction Application

V. Emissions Estimations of Criteria Pollutants (See Appendix C of NOC Application)

Does your project generate air pollutant emissions? ☒ Yes ☐ No

If yes, provide the following information about your air pollutant emissions:

☒ Air pollutants emitted, such as carbon monoxide (CO_2), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), and volatile organic compounds (VOC), particulate matter ($PM_{2.5}$, PM_{10}, TSP), sulfur dioxide (SO_2)

☒ Potential emissions of criteria air pollutants in tons per hour, tons per day, and tons per year (include calculations)

☒ Fugitive air pollutant emissions – pollutant and quantity

VI. Emissions Estimations of Toxic Air Pollutants (See Appendix C of NOC Application)

Does your project generate toxic air pollutant emissions? ☒ Yes ☐ No

If yes, provide the following information about your toxic air pollutant emissions:

☒ Toxic air pollutants emitted (specified in WAC 173-460-150[1])

☒ Potential emissions of toxic air pollutants in pounds per hour, pounds per day, and pounds per year (include calculations)

☒ Fugitive toxic air pollutant emissions - pollutant and quantity

VII. Emission Standard Compliance (See Section 4 of NOC Application)

Does your project comply with all applicable standards identified? ☒ Yes ☐ No

☒ Provide a list of all applicable new source performance standards, national emission standards for hazardous air pollutants, national emission standards for hazardous air pollutants for source categories, and emission standards adopted under the Washington Clean Air Act, Chapter 70.94 RCW.

VIII. Best Available Control Technology (See Section 5 of NOC Application)

☒ Provide a complete evaluation of Best Available Control Technology (BACT) for your proposal.

[1] http://apps.leg.wa.gov/WAC/default.aspx?cite=173-460-150

Notice of Construction Application

IX. Ambient Air Impacts Analyses (See Section 6 of NOC Application)

Does your project cause or contribute to a violation of any ambient air quality standard or acceptable source impact level? ☐ Yes ☒ No

Provide the following:

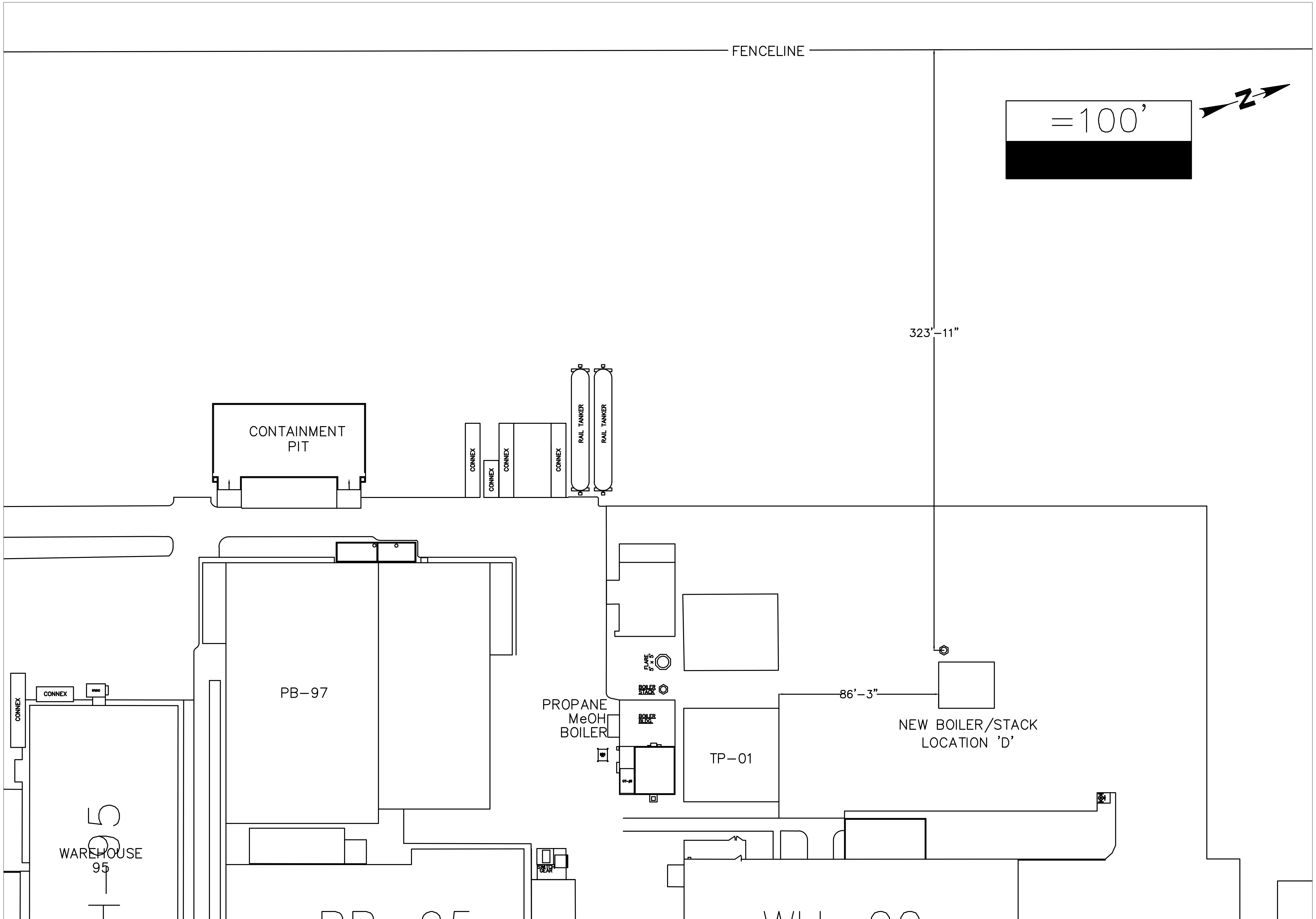
☒ Ambient air impacts analyses for criteria air pollutants (including fugitive emissions)

☒ Ambient air impacts analyses for toxic air pollutants (including fugitive emissions)

☒ Discharge point data for each point included in ambient air impacts analyses (include only if modeling is required)

- ☒ Exhaust height
- ☒ Exhaust inside dimensions (diameter or length and width)
- ☒ Exhaust gas velocity or volumetric flow rate
- ☒ Exhaust gas exit temperature
- ☒ Volumetric flow rate
- ☒ Discharge description (i.e., vertically or horizontally) and if there are any obstructions (e.g., raincap)
- ☒ Emission unit(s) discharging from the point
- ☒ Distance from the stack to the nearest property line
- ☒ Emission unit building height, width, and length
- ☒ Height of tallest building on-site or in the vicinity, and the nearest distance of that building to the exhaust
- ☒ Facility location (urban or rural)

APPENDIX B: SITE PLAN



"CONTROLLED DOCUMENT – DO NOT COPY",

PROJECT NUMBER	DRAWN BY	CHECKED BY	DATE	REVISION	SHEET NO.	NO. OF SH
	BBG		06/18	0	1	1

MLI
MOSES LAKE INDUSTRIES, INC.
8248 Randolph Rd. NE
Moses Lake, WA 98837
Phone: (509) 762-5336
Fax: (509) 762-5981

TITLE

MOSES LAKE INDUSTRIES, INC. SIMPLIFIED SITE PLAN NEW BOILER LOCATION

SCALE	FILE NAME	DRAWING NUMBER
N/A	1C00XXXXX	1-C-XXXXX

CONFIDENTIAL

NO.	REVISIONS	BY	CKD.	APPD	DATE	NO.	REVISIONS	BY	CKD.	APPD	DATE	REFERENCES	NO.	ISSUED FOR	TRANSMITTAL
0	CREATED DRAWING FOR REVIEW	BBG			04/16										

APPENDIX C: EMISSION CALCULATIONS

Section C1. Boiler #2 Emission Calculations

> As part of MLI's proposed TMAC Product Quality/Emissions Upgrade project for the Moses Lake facility, MLI will be installing a second boiler (Boiler #2).

> As a new unit, potential emissions from Boiler #2 represent project-related emissions increases that must demonstrate compliance with the Washington New Source Review (NSR) requirements under WAC 173-400-110 for criteria pollutants and WAC 173-460-040 for TAPs.

> Boiler #2 will combust either pipeline quality natural gas or methanol co-product generated by the Moses Lake facility. MLI is proposing an annual methanol usage limit of 1,201,000 gallons per year, which corresponds to operating the boiler such that methanol provides 50% of the unit's annual rated heat input capacity. As presented in Table C1-5, the worst-case hourly emission rates for Boiler #2 are the greater emission rates from firing natural gas only or methanol only at the boiler's maximum capacity. The worst-case annual emissions are the greater emissions rates from either (1) firing natural gas only for the entire year, or (2) firing methanol at the proposed operating limit and firing natural gas during the remainder of annual operations at the boiler's maximum capacity.

Table C1-1. New 400 HP Boiler Parameters and Constants

Maximum Operating Hours	8,760	hr/year
Maximum Boiler Capacity [a]	16.70	MMBtu/hr
F-Factor [b]	8,710	dscf/MMBtu
Exhaust Flow Rate (0% O_2) [c]	2,424	dscf/min
Exhaust Flow Rate (3% O_2) [c]	2,772	dscf/min
Standard Pressure	1	atm
Standard Temperature	68	^oF
	528	^oR
Ideal Gas Constant (R)	1	scf-atm/(^{o}R-lbmol)
Molecular Weight of NO_2	46.01	lb/lbmol
Molecular Weight of CO	28.01	lb/lbmol

[a] The maximum heat input capacity is based on the Cole Industrial quoted capacity for the 30 ppm NOx boiler. This corresponds to a boiler output rating of 400 hp and an efficiency of 80.2% at this maximum firing scenario.

[b] The F-factor for natural gas firing is from EPA Method 19. This F-factor is assumed to be representative of methanol as well; both methane (primary constituent in natural gas) and methanol contain a single carbon atom, so the stoichiometric ratios to complete the combustion reaction are similar. This assumption is supported by the results of MLI's recent source testing on its existing boiler, which show close agreement between the boiler exhaust rate when firing methanol and natural gas at similar heat input rates.

[c] The exhuast flow rate is calculated as the product of the boiler's rated heat input capacity and the F-factor. This flow rate is assumed to represent both natural gas and methanol combustion, and corresponds to 0% O2. For the purpose of calculating emissions using the vendor-supplied emission guarantees, which are expressed on a 3% O2 basis, these flow rates were converted to a 3% O2 basis.

Table C1-2. Methanol Co-Product Fuel Stream Specifications and Proposed Usage Limit

Maximum Heat Input from Methanol Fuel Stream [a]	73,130	MMBtu/year
Methanol Density [b]	6.61	lb/gal
Methanol Higher Heating Value [c]	9,212	Btu/lb
	0.0609	MMBtu/gal
Proposed Methanol Usage Limit (Boiler #2)	1,201,000	gal/year

[a] The maximum annual heat input from methanol fuel combustion in Boiler #2 assumes that methanol is fired for up to 50% of the unit's annual rated heat input capacity.

[b] The density of the methanol co-product stream is based on sampling conducted by MLI.

[c] The Higher Heating Value (HHV) of the methanol co-product produced by the MLI facility was determined as part of the 2017 source test on Boiler #1.

Table C1-3. Potential Emissions from the New 400 HP Boiler - Natural Gas Combustion

Operating Hours on Natural Gas	8,760	hr/year
Natural Gas Heating Value [a]	1,030	Btu/scf
Vendor Guarantee for NO_x [b]	30	ppmvd @ 3% O_2
	0.036	lb/MMBtu
Vendor Guarantee for CO [b]	50	ppmvd @ 3% O_2
	0.036	lb/MMBtu

Pollutant		Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)
PM (filterable only)	c	1.9	0.002	0.03	0.13
PM_{10}	c	7.6	0.007	0.12	0.54
$PM_{2.5}$	c	7.6	0.007	0.12	0.54
SO_2	c	0.6	0.001	9.73E-03	0.04
NO_x	b	--	0.036	0.60	2.61
VOC	c	5.5	0.005	0.09	0.39
CO	b	--	0.036	0.60	2.65
TAPs					
Benzene	d	5.80E-03	5.63E-06	9.40E-05	4.12E-04
Formaldehyde	d	1.23E-02	1.19E-05	1.99E-04	8.73E-04
Naphthalene	d	3.00E-04	2.91E-07	4.86E-06	2.13E-05
Acetaldehyde	d	3.10E-03	3.01E-06	5.03E-05	2.20E-04
Acrolein	d	2.70E-03	2.62E-06	4.38E-05	1.92E-04
Propylene	d	5.30E-01	5.15E-04	8.59E-03	3.76E-02
Toluene	d	2.65E-02	2.57E-05	4.30E-04	1.88E-03
Xylene	d	1.97E-02	1.91E-05	3.19E-04	1.40E-03
Ethylbenzene	d	6.90E-03	6.70E-06	1.12E-04	4.90E-04
Hexane	d	4.60E-03	4.47E-06	7.46E-05	3.27E-04
CO_2e	e		--	1,955	8,563
CO_2	f	--	116.98	1,953	8,555
N_2O	f	--	2.20E-04	3.68E-03	0.02
CH_4	f	--	2.20E-03	0.04	0.16

[a] The natural gas heating value corresponds to the default heating value for pipeline quality natural gas that is used as the basis for EPA's SCR cost calculations template.

[b] The emissions guarantees for NOx and CO exhaust concentrations were provided by Cole Industrial, the vendor for the proposed boiler. These were converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law.

[c] Emission factors for small boilers (<100 MMBtu/hr) are obtained from Table 1.4.1 and Table 1.4.2, AP-42 Chapter 1.4, Natural Gas Combustion. These factors are converted from a lb/MMscf basis to a lb/MMBtu basis using the heating value of natural gas. PM emissions represent filterable PM only, while PM10 and PM2.5 emissions include both filterable and condensable PM emissions of the associated size.

[d] Natural gas emission factors are obtained from the Ventura County Air Pollution Control District's AB 2588 Combustion Emission Factors document, dated May 17, 2001. Based on the size of the proposed boiler, the factors for 10-100 MMBtu/hr units are used.

[e] The GHGs emissions are calculated based on the Global Warming Potentials (GWP) provided in Table A-1 of 40 CFR 98.

CO_2	1
N_2O	298
CH_4	25

[f] The emission factors are obtained from 40 CFR 98 Subpart C, Tables C-1 and C-2, and converted to values in lb/MMBtu.

Table C1-4. Potential Emissions from the New 400HP Boiler - Methanol Combustion

Proposed Methanol Operating Limit [a]	73,130	MMBtu/year
	1,201,000	gal/year
Vendor Guarantee for NOx [b]	112	ppmvd @ 3% O2
	0.133	lb/MMBtu
Vendor Guarantee for CO [b]	100	ppmvd @ 3% O2
	0.072	lb/MMBtu

Pollutant [c]	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)
PM (filterable only) [d]	--	0.03	0.50	1.10
NO_x [b]	--	0.133	2.22	4.87
CO [b]	--	0.072	1.21	2.65
VOC [e]	--	--	0.34	0.75
TAPs	--			
TMA [f]	--	--	0.02	0.05
Methanol [f]	--	--	0.23	0.50

[a] The proposed operating limit for methanol fuel combustion in Boiler #2 assumes that methanol is fired for up to 50% of the unit's maximum annual capacity. This corresponds to a fuel usage limit of 1,201,000 gallons co-product methanol per year.

[b] The emissions guarantees for NOx and CO exhaust concentrations were provided by Cole Industrial, the vendor for the proposed boiler. These were converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law. The NOx emission factor accounts for thermal NOx from pure methanol combustion and NOx from fuel-bound nitrogen.

[c] For all other pollutants not represented in this table, hourly emissions from methanol combustion are assumed to be equivalent to hourly emissions from natural gas combustion.

[d] The PM (filterable) emission factor for methanol combustion corresponds to the limit established by 40 CFR 63 Subpart JJJJJJ for new boilers firing liquid fuels.

[e] The VOC emission rate associated with methanol fuel combustion corresponds to the sum of (1) estimated TMA emissions (see footnote f), (2) estimated methanol emissions (see footnote f), and (3) estimated miscellaneous VOC emissions (calculated using the AP-42 factor from Table 1.4-2, scaled by the unit's heat input capacity).

[f] The projected methanol and TMA emission rates from Boiler #2 (1,000 lb/yr and 100 lb/yr, respectively) are based on MLI's operating experience and correspond to a combustion efficiency of 99.99% for methanol and 99.6% for TMA (based on a TMA concentration in the methanol co-product stream of approximately 3,300 ppmw, per MLI's sampling results). The 2017 source test results for Boiler #1, which showed that the exhaust concentrations of both TMA and methanol were less than the associated method detection limits (MDLs), verify that these estimates are conservative. However, because Boiler #2 will implement a Flue Gas Recirculation (FGR) system, which will reduce the operating temperature of the new system and potentially increase VOC emissions relative to Boiler #1, MLI does not wish to use the Boiler #1 source test results to estimate methanol and TMAC emissions from the proposed boiler.

Table C1-5. Potential Emissions from the New 400HP Boiler - Worst Case [a]

Pollutant	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tpy)
PM (filterable only)	0.50	1.16
PM_{10}	0.12	0.54
$PM_{2.5}$	0.12	0.54
SO_2	0.01	0.04
NO_x	2.22	6.17
VOC	0.09	0.94
CO	1.21	3.97
Benzene	9.40E-05	4.12E-04
Formaldehyde	1.99E-04	8.73E-04
Naphthalene	4.86E-06	2.13E-05
Acetaldehyde	5.03E-05	2.20E-04
Acrolein	4.38E-05	1.92E-04
Propylene	8.59E-03	3.76E-02
Toluene	4.30E-04	1.88E-03
Xylene	3.19E-04	1.40E-03
Ethylbenzene	1.12E-04	4.90E-04
Hexane	7.46E-05	3.27E-04
TMA	2.28E-02	5.00E-02
Methanol	2.28E-01	5.00E-01
CO_2e	1,955	8,563

[a] The worst-case hourly emission rates for Boiler #2 are the greater emission rates from firing natural gas only or methanol only at the boiler's maximum capacity. The worst-case annual emission rates are the greater emission rates from the following scenarios:
Scenario 1: Firing natural gas at the boiler's maximum capacity for 8,760 hours per year;
Scenario 2: Firing methanol at the proposed operating limit and firing natural gas the remainder of the time at the boiler's maximum capacity.

Section C2. Fugitive Emissions from Piping Components

> As part of MLI's proposed TMAC Product Quality/Emissions Upgrade project for the Moses Lake facility, MLI will be adding and upgrading various valves, connectors, pumps, and related piping components.

> The majority of project-related changes will replace existing piping components with components that are larger in size. Because fugitive emission calculations for piping components do not depend on the component size, these upgrades are not expected to impact emissions. However, various new piping components will also be added.

> Piping components associated with MLI's existing TMAC process are currently subject to the Leak Detection and Repair (LDAR) requirements of NSPS Subpart VV. Following the proposed expansion project, the TMAC process at MLI's Moses Lake facility will be subject to the LDAR requirements of NSPS Subpart VVa rather than NSPS Subpart VV. Considering the reduced leak detection threshold for certain components under NSPS Subpart VVa, and the fact that repairs will potentially be initiated at lower leak rates, MLI does not expect actual fugitive emissions from existing components to increase relative to past actual emissions.

> Actual emissions from existing piping components are calculated using monitoring results from MLI's current LDAR program. These monitoring results are converted to emission rates by applying the SOCMI correlation equations provided in Table 2-9. SOCMI Industry Leak Rate/Screening Value Correlations in the Protocol for Equipment Leak Emission Estimates, EPA 453/R-95-017, November 1995. The default zero values from Table 2-11 of this protocol are also applied to calculate the facility's actual emissions.

> To conservatively account for year-to-year variability in fugitive emissions, and to accommodate emissions from new piping components associated with the proposed project, MLI proposes the following calculations for fugitive emissions from piping components at the Moses Lake facility.

> As the existing piping components do not represent a source of project-related emissions increases, only emissions from the new piping components are considered in the TAPs screening evaluation required under WAC 173-460.

Table C2-1. Past Actual Reported Fugitive Emissions from TMAC Piping Components[a]

Reporting Year	Methanol (lbs)	TMA (lbs)	DMC (lbs)	Total VOC (lbs)
2012	2,262.4	90.7	262.8	2,615.9
2013	3,238.0	149.4	475.1	3,862.5
2014	2,885.3	130.2	343.9	3,359.4
2015	2,518.8	119.5	342.5	2,980.8
2016	2,295.7	231.3	409.6	2,936.6
2017	2,013.2	176.5	296.8	2,486.5
Maximum	***3,238.0***	***231.3***	***475.1***	***3,862.5***

[a] The annual fugitive emission rates from piping components in Table 2-1 represent the results of LDAR-related monitoring, converted to emission rates in accordance with the methodology prescribed by EPA's Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017). These estimates serve as the basis for the actual annual emissions reported each year to Ecology.

Table C2-2. Post-Project Fugitive Emissions from Piping Components

Parameter	Methanol	TMA	Total VOC
Maximum Actual Reported Emissions (lbs/yr)	3,238.0	231.3	3,862.5
Potential Emissions from Existing Components (lbs/yr) [a]	6,476.0	462.6	7,725.0
Potential Emissions from New Components (lbs/yr) [b]	1,619.0	115.7	1,931.3
Potential Emissions from New Components (tpy) [b]	0.81	0.06	0.97
Total Post-Project Emissions (lb/yr)	8,095.0	578.3	9,656.3
Total Post-Project Emissions (tpy)	4.05	0.29	4.83
Permit Limit (tpy) [c]	--	--	12.52
Permit Limit (lb/yr) [c]	11,621	3,000	--
Estimate in Compliance with Permit Limit?	***Yes***	***Yes***	***Yes***

[a] Potential emissions from existing components are calculated as the maximum reported actual emission rate from 2012 through 2017, scaled by a factor of 200% for conservatism. As described in the introduction to Section 2 in this workbook, given the project-related transition from NSPS Subpart VV to NSPS Subpart VVa and the more stringent leak detection thresholds associated with the NSPS Subpart VVa LDAR plan, MLI does not anticipate actual reported fugitive emissions from existing piping components to increase following the project.

[b] For conservatism, potential emissions from new piping components associated with the proposed project are assumed to be equal to 25% of the projected potential emission rate for existing piping components. MLI is still in the process of quantifying the number of new components, but anticipates that the component counts will increase by less than 25%. Accordingly, the 25% scaling factor conservatively represents worst-case new component emissions.

[c] The current permit limits for fugitive emissions are established by Condition 4.6 of Approval Order No. 16AQ-E022. The permitted VOC and TMA limits for fugitives also account for emissions from TMA unloading, hose purging, and maintenance. Since these emissions are unaffected by the project, they are not presented here. However, based on past estimates, the currently permitted fugitive VOC and TMA limits are sufficient to accommodate emissions from these additional fugitive sources.

Section C3. Flare Emissions

> Vents to the flare are not expected to increase as a result of the proposed TMAC Product Quality/Emissions Upgrade project for the Moses Lake facility. Given the process improvements, particularly with respect to the vent condenser upgrades and cross-over lines, MLI expects actual vents to the flare to decrease following the project.

> In spite of the expected actual decrease in emissions from the flare, MLI is requesting an increase to the methanol emission limit established by Approval Order No. 16AQ-E022 for the flare. This request does not represent a project-related increase in methanol emissions from the flare. Rather, based on the results of flare inlet testing and an estimated control efficiency, the current permit limit for methanol does not adequately represent the worst-case flare venting rates at the current TMAC production limit for the Moses Lake facility. In a letter to Ecology dated August 29, 2008, MLI requested an increase in the flare's TMA emission limit to better represent source test results for TMA. This request was approved by Ecology and the permit limit was updated; however, a similar change to the methanol emission limit was not requested at the time. Therefore, MLI is requesting a similar change to the methanol limit at this time.

> As MLI's proposed upgrade project does not involve a TMAC production increase or a change to the maximum venting rate to the flare, the requested increase to the flare's methanol emission limit is unrelated to the project and does not trigger tBACT or TAPs screening evaluation required under WAC 173-460.

Table C3-1. Potential Methanol Emissions from Flare

Methanol Emissions from Flare, Based on Current Permit (lb/yr) [a]	1,422
Revised Methanol Emissions from Flare/New Permit Limit Requested by MLI (lb/yr) [b]	3,022
Flare Control Efficiency Requested by MLI [c]	99%

[a] The current permit limit for methanol emissions from the flare is established by Condition 4.6 of Approval Order No. 16AQ-E022.

[b] MLI requests that 1,600 lbs of methanol emissions be moved from the fugitive limit to the flare limit. As described in the introduction to Section C2, based on conservative estimates for fugitive emissions from piping components, MLI will continue to comply with the fugitive methanol limit at this reduced level. The increased methanol limit for the flare will ensure that the limit adequately represents the current venting capacity of the TMAC process (at the maximum permitted TMAC production rate), without increasing the overall methanol emission rate for the facility. MLI proposes to demonstrate compliance with this limit by testing the inlet stream to the flare and applying a standard flare control efficiency for methanol, as described by footnote (c) to this table.

[c] Table 4 of TNRCC's document prescribes a 99 percent DRE for "compounds containing no more than 3 carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide and propylene oxide." Because this increased DRE is specifically recommended for methanol vents controlled by a flare, MLI proposes to use this efficiency along with the flare inlet test data to demonstrate compliance with the revised limit.

Section C4. TAPS Screening

> WAC 173-460-070 requires a NOC application to demonstrate that project-related increases in TAP emissions "are sufficiently low to protect human health and safety from potential carcinogenic and/or other toxic effects." MLI is satisfying this requirement by completing a First Tier Review of TAP emissions in accordance with WAC 173-460-080.

> According to WAC 173-460-080, a NOC application must include an Acceptable Source Impact Level (ASIL) analysis for each TAP emitted by the new or modified emission units with an emission increase greater than the de minimis emission level. The ASIL requirement can be satisfied for any TAP using either dispersion modeling (i.e., by demonstrating that the modeled ambient impact of the aggregate emissions increase of each TAP does not exceed the corresponding ASIL) or a Small Quantity Emission Rate (SQER) evaluation (i.e., by showing that the proposed increase in emissions of a TAP is less than the corresponding SQER).

> Project-related emission increases are limited to proposed potential emissions from Boiler #2 and fugitive emission increases associated with the installation of new piping components. While flare emission calculations are discussed in this emission inventory, the proposed increase to the permitted methanol emission limit for the flare is unrelated to the project, as detailed in Section C3. Because the flare does not represent a source of project-related emissions increases, flare emissions are not considered in the TAPs screening evaluation required under WAC 173-460.

> The following table compares project emissions increases to the corresponding TAP thresholds established by WAC 173-460-150. As demonstrated by this table, only project-related NO_2 emissions exceed the SQER and trigger dispersion modeling requirements.

Table C4-1. HAPs/TAPs Emission Summary

Pollutant	CAS Number	HAP?	TAP?	Emissions [a] Hourly TAPs (lb/hr)	Emissions [a] Annual TAPs (tpy)	Averaging Period	ASIL ($\mu g/m^3$)	SQER (lb/avg. period)	De Minimis (lb/avg. period)	Modeling Required?
Benzene	71-43-2	Yes	Yes	9.40E-05	4.12E-04	year	0.0345	6.62	0.331	No
Formaldehyde	50-00-0	Yes	Yes	1.99E-04	8.73E-04	year	0.167	32	1.6	No
Naphthalene	91-20-3	Yes	Yes	4.86E-06	2.13E-05	year	0.0294	5.64	0.282	De Minimis
Acetaldehyde	75-07-0	Yes	Yes	5.03E-05	2.20E-04	year	0.37	71	3.55	De Minimis
Acrolein	107-02-8	Yes	Yes	4.38E-05	1.92E-04	24-hr	0.06	0.00789	0.000394	No
Propylene	115-07-1	No	Yes	8.59E-03	0.04	24-hr	3000	394	19.7	De Minimis
Toluene	108-88-3	Yes	Yes	4.30E-04	1.88E-03	24-hr	5000	657	32.9	De Minimis
Xylene[b]	108-38-3	Yes	Yes	3.19E-04	1.40E-03	24-hr	221	29	1.45	De Minimis
Ethylbenzene	100-41-4	Yes	Yes	1.12E-04	4.90E-04	year	0.4	76.8	3.84	De Minimis
Hexane[c]	110-54-3	Yes	Yes	7.46E-05	3.27E-04	24-hr	700	92	4.6	De Minimis
Methanol[d]	67-56-1	Yes	Yes	0.41	1.31	24-hr	4000	526	26.3	De Minimis
SO_2	7446-09-05	No	Yes	9.73E-03	0.04	1-hr	660	1.45	0.457	De Minimis
NO_2[e]	10102-44-0	No	Yes	2.22	6.17	1-hr	470	1.03	0.457	**Yes**
CO	630-08-0	No	Yes	1.21	3.97	1-hr	23000	50.4	1.14	No
Total				**3.87**	**11.54**					

[a] Because fugitive emission rates are assumed to be continuous over time for emission calculation purposes, differences between short-term and long-term emission rates for the project are associated with the operation of Boiler #2. Specifically, the worst-case hourly TAP emission rates for the upgrade project are the greater emission rates from firing natural gas only or methanol only at the Boiler #2's maximum capacity.
The worst-case annual TAP emission rates for the upgrade project are the greater emission rates from the following scenarios:
Scenario 1: Firing natural gas at the Boiler #2's maximum capacity for 8,760 hours per year;
Scenario 2: Firing methanol at the proposed operating limit and firing natural gas the remainder of the time at the Boiler #2's maximum capacity.

[b] For conservatism, it is assumed that all xylene is in the form of m-xylene (WAC 173-460 establishes identical thresholds for m-, o-, and p-xylene).

[c] For conservatism, it is assumed that all hexane is in the form of n-hexane.

[d] The methanol emission rate represents both the boiler emissions and fugitive emissions from new piping components.

[e] It is conservatively assumed that all NO_X is emitted in the form of NO_2.

Section C5. Requested Changes to Emission Limits

> Condition 4.6 of Approval Order No. 16AQ-E022 establishes maximum annual emisssion limitations for the permitted sources at MLI's TMAC production facility.

> Table C5-1 documents these currently applicable emission limits.

> Table C5-2 identifies MLI's requested changes to these permit limits based on the proposed upgrade project and MLI's requested revision to the flare's methanol emission rate to better represent the system's current capacity. As described in Section C3, the requested change to the flare emission limit is unrelated to the project.

Table C5-1. Summary of Current Permit Limits

Pollutant	Source				Units
	Boiler	Flare	Fugitive	Total	
NOx	7.5	6.99	--	14.5	tons/yr
CO	2.0	2.0	--	4.0	tons/yr
VOC (in actual weight)	1.79	6.49	12.52	20.80	tons/yr
TAPs (total)[a]	0.91	5.20	25.56	31.67	tons/yr
Methanol	1,740	1,422	11,621	14,783	lbs/yr
TMA[b]	20	5,000	3,000	8,020	lbs/yr

a During MLI's meeting with Ecology on June 15, 2018, Ecology discussed removing the TAPs (total) limit from the permit, as it is not necessary from a regulatory perspective.

b TMA is no longer a regulated TAP under WAC 173-460.

> To accommodate the proposed TMAC facility upgrade project, MLI proposes the following emission limits.

Table C5-2. Proposed Permit Limits
***Changes Denoted in Bold Italics**

Pollutant	Source					Units
	Boiler #1	Boiler #2[a]	Flare	Fugitive	Total	
NOx	7.5	***6.17***	6.99	--	***20.7***	tons/yr
CO	2.0	***4.0***	2.0	--	***8.0***	tons/yr
VOC (in actual weight)	1.79	***0.94***	6.49	12.52	***21.74***	tons/yr
TAPs (total)[b]	***--***	--	***--***	***--***	***--***	--
Methanol[c]	1,740	***1,000***	***3,022***	***8,095***	***13,857***	lbs/yr
TMA[a,d]	20	***100***	***4,900***	3,000	8,020	lbs/yr

a Boiler #2 is a new emission unit associated with the proposed upgrade project. Therefore, all Boiler #2 table entries represent new permit limits.

b Based on Ecology's feedback during the June 15, 2018 meeting with MLI, MLI proposes removing the total TAPs limits from the permit.

c Potential fugitive emissions of methanol from piping components are conservatively quantified using the methodology described in Section C2 of this appendix. The result of this methodology represents a decrease of approximately 3,500 lbs/yr relative to the current permit limit for fugitive methanol emissions. As such, MLI requests that 1,600 lbs/yr of the current permit limit be reallocated to the flare to more accurately represent the flare's current emissions profile for the maximum TMAC production scenario. As described in Section C2, the requested increase to the flare's methanol emission limit is unrelated to the project. Furthermore, MLI requests that 1,000 lbs/yr of the current permit limit be reallocated to Boiler #2 to represent emission increases from the proposed project. This reallocation strategy ensures that facility-wide permitted methanol emissions do not increase as a result of the upgrade project or flare limit adjustment.

d TMA is no longer a regulated TAP under WAC 173-460. As such, MLI would be supportive of Ecology removing TMA limits from the permit. However, MLI has included proposed TMA limits in this table to be comprehensive. MLI proposes that 100 lbs/yr of TMA emissions currently allocated to the flare be reallocated to Boiler #2 to represent emission increases from the proposed project. Due to the process improvements associated with the proposed upgrade project, the actual flare venting rate is expected to decrease at the facility's maximum TMAC production rate. Consequently, even at the maximum anticipated TMAC production rate, MLI will be able to demonstrate compliance with this reduced TMA limit for the flare. This reallocation strategy ensures that facility-wide permitted TMA emissions do not increase as a result of the upgrade project.

APPENDIX D: BACT COST CALCULATIONS

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	16.70	MMBtu/hour
What is the higher heating value (HHV) of the fuel?	1,030	Btu/scf
What is the estimated actual annual fuel consumption?	142,000,757	scf/Year
Enter the net plant heat input rate (NPHR)	8.2	MMBtu/MW
Plant Elevation	1070	Feet above sea level

*HHV value of 1030 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	2.35	11,814
Sub-Bituminous	0	0.31	8,730
Lignite	0	0.91	6,534

Please click the calculate button to calculate weighted values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	

Inlet NO_x Emissions (NOx_{in}) to SCR	0.08 lb/MMBtu
NOx Removal Efficiency (EF) provided by vendor	90 percent
Stoichiometric Ratio Factor (SRF)	0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Number of empty catalyst layers (R_{empty})	1
Ammonia Slip (Slip) provided by vendor	2 ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	25 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	417 °F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	50 percent*
Density of reagent as stored (ρ_{stored})	71 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3
19% aqueous NH_3	58 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SCR:

Desired dollar-year	2017	
CEPCI for 2017	567.5 Enter the CEPCI value for 2017	584.6 2012 CEPCI
Annual Interest Rate (i)	7 Percent	
Reagent ($Cost_{reag}$)	1.62 $/gallon for a 50 percent solution of urea	
Electricity ($Cost_{elect}$)	0.0328 $/kWh	
Catalyst cost ($CC_{replace}$)	160.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst*	
Operator Labor Rate	60.00 $/hour (including benefits)*	
Operator Hours/Day	4.00 hours/day*	

CEPCI = Chemical Engineering Plant Cost Index

* $160/cf is a default value for the catalyst cost. User should enter actual value, if known.

* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	1.62	Based on the average of vendor quotes from 2011 - 2013.	
Electricity Cost ($/kWh)	0.071	Average annual electricity cost for utilities is based on 2014 electricity production cost data for fossil-fuel plants compiled by the U.S. Energy Information (EIA). Available at http://www.eia.gov/tools/faqs/faq.cfm?id=19&t=3.	
Percent sulfur content for Coal (% weight)	2.35	Average sulfur content based on U.S. coal data for 2014 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	1,030	2014 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	160	Cichanowicz, J.E. "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies", July 2013.	

Design Information and Assumptions for Heating Exhaust Stream to Required SCR Temperature

New 16.7 MMBtu/hr Boiler - NOx Emissions Profile and Exhaust Gas Conditions

Parameter	Parameter Per Reheater	Units	Reference/Notes
Maximum Heat Input Capacity	16.7	MMBtu/hr	Heat input capacity from Cole Industrial quote dated 6/20/2018
Maximum Annual Gas Usage Rate	142.0	MMscf/yr	Proposed operating constraint
High Heating Value of Natural Gas at Plant	1,030	Btu/scf	Default value used by EPA's SCR cost template spreadsheet
Inlet Temperature	417	^{o}F	Average stack temperature for existing boiler firing methanol fuel stream (per 2017 source test)
Stack Gas Dry Standard Volumetric Flow Rate, at 68^{o}F	2,772	dscfm	The exhaust flow rate is calculated as the product of the boiler's rated heat input capacity and the applicable F-factor (8,710 dscf/MMBtu). This flow rate is assumed to represent both natural gas and methanol combustion, and corresponds to 0% O2. This flow rate is converted to a 3% O2 basis to better represent the stream that would be routed to a SCR system.
NOx Emission Factor (firing methanol)	0.133	lb/MMBtu	The emissions guarantee for NOx exhaust concentrations (90 ppmvd) from the methanol-fired boiler equipped with the base FGR system was provided by Cole Industrial, the vendor for the proposed boiler. This concentration was converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law.
Maximum Portion of Year Boiler Will Operate on Methanol Fuel Stream	50%	percent	MLI has proposed an operational limit that corresponds to a maximum 50% annual capacity factor for methanol.
NOx Emission Factor (firing natural gas)	0.036	lb/MMBtu	The emissions guarantee for NOx exhaust concentrations (30 ppmvd) from the natural gas-fired boiler equipped with the base FGR system was provided by Cole Industrial, the vendor for the proposed boiler. This concentration was converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law.
Maximum Annual NOx Emission Rate	6.17	tpy	Calculated using the NOx EFs and capacity of boiler; assuming continuous annual operations and accounting for the portion of year boiler will be firing methanol vs. natural gas
Maximum Hourly NOx Emission Rate	2.22	lb/hr	Calculated from NOx EF for methanol combustion (for conservatism) and capacity of boiler

Preheater Design Basis

Parameter	Parameter Per Reheater	Units	Reference/Notes
Exhaust Flow Rate, Mass Basis	12,473	lb/hr	Dry standard volumetric flow rate converted to mass basis using standard molar volume of an ideal gas and molecular weight of air
Desired Exhaust Stream Temperature (going to SCR)	700	^{o}F	Optimal Temperature for SCR Operation
Mean Heat Capacity of Exhaust Stream	0.255	Btu/(lb-^{o}F)	EPA's CCM Section 3.2 Chapter 2, page 2-26; represents the mean heat capacity of air between 77F and 1375F (the average temperature of the waste gas entering and leaving the preheater)
Heat Required to Increase Exhaust Temperature	72	Btu/lb	Calculation of heat required to raise one pound of exhaust gas from exhaust temperature (417 F) to desired temperature for SCR (700 F)
Preheater Size Requirement (No Energy Recovery)	0.90	MMBtu/hr	Calculation of natural gas usage required to increase exhaust gas temperature to desired level; no energy recovery
Energy Recovery Rate	0.70	--	EPA's CCM Section 3.2 Chapter 2, page 2-8; represents maximum energy recovery accomplished by recuperative incinerator
Preheater Size Requirement (with Energy Recovery)	0.27	MMBtu/hr	Calculation of preheater size required to increase exhaust gas temperature to desired level; accounting for maximum energy recovery rate
Natural Gas Usage (with Energy Recovery)	4.37	acfm	Calculation based on Preheater size requirement and HHV of natural gas
Natural Gas Usage (Annual)	2.30	MMcf/yr	Calculation of annual natural gas usage required to increase exhaust gas temperature to desired level; accounting for maximum energy recovery rate
Natural Gas Cost for Preheating	$ 17,454	$	Cost estimate for natural gas required for preheating based on annual usage and natural gas cost per Mcf
NOx Emissions from Natural Gas Usage for Preheating	0.01	lb/hr	Calculation based on Preheater size requirement and NOx EF from AP-42 Chapter 1.4 for external combustion sources with low NOx burners

Constants and Unit Conversions

Constants	Value	Units	Reference/Notes
Standard Molar Volume	386	scf/lbmol	
Molecular Weight of Dry Air	28.95	lb/lbmol	Molecular weight calculated for dry air based on 77.9% N2, 20.9% O2, and 0.9% Ar
Conversions	Value	Units	Reference/Notes
Minutes per Hour	60	min/hr	
Hours per Year	8,760	hr/yr	
Days per Year	365	days/yr	
Utility Costs, Employee Wages			
Natural Gas Price	$7.6	per Mcf	Most recent natural gas pricing data available for WA (March 2018), per https://www.eia.gov/dnav/ng/hist/n3035wa3M.htm
Chemical Engineering Plant Cost Indices			
2017	567.5	--	2017 cost index used since 2018 annual index not yet available

Trinity Consultants

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	16.7	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	142,000,757	scf/Year	
Actual Annual fuel consumption (Mactual) =		142,000,757	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.00	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOxin- NOxout)/NOxin =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	1.27	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	5.56	tons/year	
NOx removal factor (NRF) =	EF/80	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr}	6,110	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$	30.22	/hour	
Residence Time	1/V_{space}	0.03	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1E6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.2	psia	
Retrofit Factor (RF)	New Construction	0.80		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.311	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x Noxadj x Sadj x (Tadj/Nscr)	202.19	Cubic feet

Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	6	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$	12	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	7	ft^2
Reactor length and width dimentions for a square reactor =	$(A_{SCR})^{0.5}$	2.7	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	83	feet

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SFR \times MW_R)/MW_{NOx}$ =	1	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	2	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	62	gallons (storage needed to store a 14 day reagent supply)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0858

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	8.59	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 80,000 \times (200/B_{MW})^{0.35} \times BMW \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 60,670 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,270 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 9,760 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,275 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,082 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$654,782	in 2017 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$11,695	in 2017 dollars
Indirect Annual Costs (IDAC) =	$58,854	in 2017 dollars
Total annual costs (TAC) = DAC + IDAC	$70,550	in 2017 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$3,274	in 2017 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$2,600	in 2017 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$2,467	in 2017 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$3,354	in 2017 dollars
Direct Annual Cost =		$11,695	in 2017 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,667	in 2017 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$56,187	in 2017 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$58,854	in 2017 dollars

Cost Effectiveness without Preheater

Cost Effectiveness (without Preheater) = Total Annual Cost (without Preheater)/ NOx Removed/year

Total Annual Cost (TAC) without preheater =	$70,550	per year in 2017 dollars
NOx Removed =	5.56	tons/year
Cost Effectiveness =	$12,695	per ton of NOx removed in 2017 dollars

Cost Effectiveness with Preheater

Cost Effectiveness (with Preheater) = Total Annual Cost (with Preheater)/ NOx Removed/year

Total Annual Cost (TAC) with preheater =	SCR TAC without preheater + Preheating Cost	$88,003	per year in 2017 dollars
NOx Removed =		5.56	tons/year
Cost Effectiveness =		$15,835	per ton of NOx removed in 2017 dollars

Design Information and Assumptions for FGR Upgrade Implementation

New 16.7 MMBtu/hr Boiler (30 ppm Design, Base FGR Option) - NOx Emissions Profile and Exhaust Gas Conditions

Parameter	Parameter Per Reheater	Units	Reference/Notes
Maximum Heat Input Capacity	16.7	MMBtu/hr	Heat input capacity for 30 ppm NOx design from Cole Industrial quote dated 6/20/2018
NOx Emission Factor (firing methanol)	0.107	lb/MMBtu	The emissions guarantee for NOx exhaust concentrations (90 ppmvd) from the methanol-fired boiler equipped with the base FGR system was provided by Cole Industrial, the vendor for the proposed boiler. This concentration was converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law.
Maximum Portion of Year Boiler Will Operate on Natural Gas	75%	percent	MLI is proposing a methanol usage limit that corresponds to 50% of the boiler's annual capacity. However, to conservatively calculate control costs, it is assumed that natural gas is used 75% of the time.
NOx Emission Factor (firing natural gas)	0.036	lb/MMBtu	The emissions guarantee for NOx exhaust concentrations (30 ppmvd) from the natural gas-fired boiler equipped with the base FGR system was provided by Cole Industrial, the vendor for the proposed boiler. This concentration was converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law.
Maximum Annual NOx Emission Rate	3.93	tpy	Although MLI is proposing a limit that corresponds to operating the boiler on methanol up to 50% of its maximum annual capacity, the annual emission rate is calculated assuming that natural gas is fired 75% of the time. This assumption conservatively quantifies the emission reduction achieved by the upgraded FGR system (which would only operate during natural gas firing).

New 17.0 MMBtu/hr Boiler (9 ppm Design, Enhanced FGR Option) - NOx Emissions Profile and Exhaust Gas Conditions

Parameter	Parameter Per Reheater	Units	Reference/Notes
Maximum Heat Input Capacity	17.0	MMBtu/hr	Heat input capacity for 30 ppm NOx design from Cole Industrial quote dated 6/20/2018
NOx Emission Factor (firing methanol)	0.107	lb/MMBtu	The emissions guarantee for NOx exhaust concentrations (90 ppmvd) from the methanol-fired boiler equipped with the enhanced FGR system was provided by Cole Industrial, the vendor for the proposed boiler. This concentration was converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law. The enhanced FGR system does not reduce NOx emissions during methanol firing, so this guarantee is identical to the guarantee for the base FGR system.
Maximum Portion of Year Boiler Will Operate on Natural Gas	75%	percent	MLI is proposing a methanol usage limit that corresponds to 50% of the boiler's annual capacity. However, to conservatively calculate control costs, it is assumed that natural gas is used 75% of the time.
NOx Emission Factor (firing natural gas)	0.011	lb/MMBtu	The emissions guarantee for NOx exhaust concentrations (9 ppmvd) from the natural gas-fired boiler equipped with the enhanced FGR system was provided by Cole Industrial, the vendor for the proposed boiler. This concentration was converted from a ppmvd @ 3% O2 basis to a lb/MMBtu basis using these vendor guaranteed concentrations, the exhaust flowrate and heat input capacity of the proposed boiler, and the ideal gas law.
Maximum Annual NOx Emission Rate	2.61	tpy	Although MLI is proposing a limit that corresponds to operating the boiler on methanol up to 50% of its maximum annual capacity, the annual emission rate is calculated assuming that natural gas is fired 75% of the time. This assumption conservatively quantifies the emission reduction achieved by the upgraded FGR system (which would only operate during natural gas firing).

Constants and Unit Conversions

Constants	Value	Units	Reference/Notes
Standard Molar Volume	386	scf/lbmol	
Molecular Weight of Dry Air	28.95	lb/lbmol	Molecular weight calculated for dry air based on 77.9% N2, 20.9% O2, and 0.9% Ar
Conversions	**Value**	**Units**	**Reference/Notes**
Minutes per Hour	60	min/hr	
Hours per Year	8,760	hr/yr	
Days per Year	365	days/yr	
Utility Costs			
Natural Gas Price	$7.6	per Mcf	Most recent natural gas pricing data available for WA (March 2018), per https://www.eia.gov/dnav/ng/hist/n3035wa3M.htm
Electricity Price	$0.0328	per kWh	Based on industrial electricity pricing from https://www.electricitylocal.com/states/washington/moses-lake/ Since Moses Lake's electricity for industrial operations is around half of the national average, the Moses Lake rate is used for conservatism.

Cost Analysis for the Control of NO_x with FGR Upgrade Option
Capital Cost Summary

Cost	Variable	Basis	Value	Reference
Direct Costs				
Purchased Equipment Cost				
Basic Equipment and Instrumentation	BE	BE	$53,000 [a]	Vendor Estimate
Freight			[b]	Not Estimated
Total Purchased Equipment Cost	PEC	SUM	$53,000	Calculation
Installation Costs			[b]	Not Estimated
Total Direct Installation Cost	DIC	SUM	$12,800 [a]	Vendor Estimate
Total Direct Costs (including sales tax)	TDC	PEC + DIC	$71,130 [a]	Calculation/Vendor Estimate
Indirect Costs				
Engineering		TDC*0.10	$7,113 [c]	OAQPS Sixth Edition
General Facilities		TDC*0.05	$3,556 [c]	OAQPS Sixth Edition
Process Contingency		TDC*0.05	$3,556 [c]	OAQPS Sixth Edition
Total Indirect Cost	TIC	SUM	$14,226	Calculation
Total Capital Investment (TCI)		**TDC + TIC**	**$85,356**	**Calculation**

[a] Costs of FGR Upgrade option provided by Jason Herbst of Cole Industrial in an email dated June 21, 2018 to Pat Blau of MLI. A sales tax rate of 8.1% is applied to the equipment cost and installation cost estimate, per Cole Industrial's recommendation.

[b] Not Estimated

[c] Office of Air Quality Planning and Standards (OAQPS), OAQPS Control Cost Manual, Sixth Edition, Section 4.2 Chapter 2, EPA/452/B-02-001, William M. Vatavuk, January 2002.

Cost Analysis for the Control of NO_x with FGR Upgrade Option
Anuual Cost Summary

Direct Operating Cost	Basis		Value	Reference
Maintenance				
Additional Maintenance Costs	3 Add'l Tune-ups at $2,500 each		$7,500 [d]	Vendor Estimate
Total Cost ($/yr)			$7,500	Calculation
Power costs				
Power Requirements	Additional fan capacity of 35 hp (26 kW)		102,492 [e]	kWh/yr, Vendor Estimate
Power Price	$/kWh	$	0.03	Local utlity costs
Total Cost ($/yr)		$	3,362	Not estimated
Total Direct ($/yr)	DAC		$10,862	
Indirect				
Overhead	60% of O&M Costs		$4,500 [c]	OAQPS Sixth Edition
Administration	2% of TCI		$1,707 [c]	OAQPS Sixth Edition
Insurance	1% of TCI		$854 [c]	OAQPS Sixth Edition
Property Tax	1% of TCI		$854 [c]	OAQPS Sixth Edition
CRF	25 Years, 7% Interest		0.086 [c]	OAQPS Sixth Edition
Capital Recovery	CRF*TCI		$7,324	Calculation
Total Indirect ($/yr)	IAC		$15,239	Calculation
Total Annual Cost (TAC=DAC+IAC)			**$26,100**	

[d] Jason Herbst of Cole Industrial recommended quarterly tune-ups for the enhanced FGR option at a cost of $2,500 to $3,000 each. $2,500 is used as the basis for this cost calculation for conservatism.

[e] Jason Herbst of Cole Industrial stated that the base FGR option would require a 15 hp blower, while the enhanced FGR option would require a 50 hp blower. If the boiler is operating near its capacity, this blower would be operating near 100% of its capacity. At the minimum boiler firing rate, this blower load would be approximately 60% of its capacity. For conservatism, the electricity cost calculation assumes that the blower is operating at 60% of it capacity during natural gas firing (where natural gas is fired at least 50% of the year).

Cost Analysis for the Control of NO_x with FGR Upgrade Option
Average Cost Effectiveness Summary

NOx baseline emission rate (ton/yr)	3.93
Additional NOx removed by FGR Upgrade (ton/yr)	1.32
Total Annual Cost (TAC) of FGR Upgrade	$26,100
Cost Effectiveness of implementing FGR Upgrade ($/additional ton NO_x removed)	$19,779

APPENDIX E: BOILER VENDOR DOCUMENTATION

Cleaver-Brooks Boiler Expected Emission Data

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Producing Steam Firing **Nat Gas**

BACKGROUND INFORMATION

Date	06/20/18	Boiler Model	CBEX Premium
Author	John Boothby	Altitude (feet)	1070
Customer	Moses Lake Industries	Operating Pressure (psig)	110.00
City & State	Moses Lake, WA	Furnace Volume (cuft)	124.60
		Furnace Heat Release (btu/hr/cu ft)	95,957
		Heating Surface (sqft)	1128
		Nox System	30

Nat Gas		Firing Rate			
		25%	**50%**	**75%**	**100%**
Horsepower		100	200	300	400
Input , Btu/hr		4,069,000	8,205,000	12,387,000	16,696,000
CO	ppm	50	50	50	50
	lb/MMBtu	0.0375	0.0375	0.0375	0.0375
	lb/hr	0.15	0.31	0.46	0.63
	tpy	0.668	1.347	2.034	2.741
NOx	ppm	30	30	30	30
	lb/MMBtu	0.0350	0.0350	0.0350	0.0350
	lb/hr	0.14	0.29	0.43	0.58
	tpy	0.624	1.258	1.899	2.560
NO	ppm	25.5	25.5	25.5	25.5
	lb/MMBtu	0.030	0.030	0.030	0.030
	lb/hr	0.12	0.24	0.37	0.50
	tpy	0.50	1.01	1.52	2.05
NO_2	ppm	4.5	4.5	4.5	4.5
	lb/MMBtu	0.005	0.005	0.005	0.005
	lb/hr	0.02	0.04	0.07	0.09
	tpy	0.12	0.25	0.38	0.51
SOx	ppm	0.34	0.34	0.34	0.34
	lb/MMBtu	0.0006	0.0006	0.0006	0.0006
	lb/hr	0.0024	0.0048	0.0073	0.0098
	tpy	0.010	0.021	0.032	0.043
VOCs	ppm	8	8	8	8
(Non-Methane Only)	lb/MMBtu	0.0036	0.0036	0.0036	0.0036
	lb/hr	0.014	0.029	0.044	0.059
VOCs does not include any background VOC emissions.	tpy	0.063	0.128	0.193	0.260
PM10 (Filterable)	ppm	N/A	N/A	N/A	N/A
	lb/MMBtu	0.0019	0.0019	0.0019	0.0019
	lb/hr	0.008	0.015	0.023	0.031
	tpy	0.033	0.067	0.101	0.136
PM10 (Condensable)	lb/MMBtu	0.0056	0.0056	0.0056	0.0056
	lb/hr	0.023	0.046	0.069	0.093
	tpy	0.100	0.201	0.303	0.409
PM2.5 (Filterable)	lb/MMBtu	0.0019	0.0019	0.0019	0.0019
	lb/hr	0.008	0.015	0.023	0.031
	tpy	0.033	0.067	0.101	0.136
PM2.5 (Condensable)	lb/MMBtu	0.0056	0.0056	0.0056	0.0056
	lb/hr	0.023	0.046	0.069	0.093
	tpy	0.100	0.201	0.303	0.409
Exhaust Data					
Temperature, F		384	423	463	502
Flow	ACFM	1,343	2,838	4,305	6,057
	SCFM (70 Degrees Fah.)	831	1,675	2,430	3,275
	DSCFM	742	1,495	2,158	2,908
	lb/hr	3,739	7,539	10,934	14,738
Velocity	ft/sec	7.13	15.06	22.84	32.13
	ft/min	428	903	1,370	1,928

Notes:

1) All ppm levels are corrected to dry at 3% oxygen.
2) Emission data based on actual boiler efficiency.
3) % H2O , by volume in exhaust gas is **17.24** % O2, by volume **2.47**
4) Water vapor in exhaust gas is **98.91** lbs/MMBtu of fuel fired
5) CO2 produced is **116.31** lbs/MMBtu of fuel fired
6) Particulate is exclusive of any particulates in combustion air or other sources of residual particulates from material.
   PM level indicated on this form is based on combustion air and fuel being clean and turndown up to 4:1.
7) Heat input is based on high heating value (HHV).
8.) Emission produced in tons per year (tpy) is based on 24 hours per day for 365 days = 8,760 hours per year
9.) Exhaust data is based on a clean and properly sealed boiler.
10.) Emission data is based on a burner turndown of 4 to 1.

14) Fuel High Heating Value = **1000** Btu/FT^3

Cleaver-Brooks Boiler Expected **Steam Perf. Data** -

- -
30 - PPM Nox System

BACKGROUND INFORMATION			The ASME Power Test Code , PTC 4.1 Heat Loss Method equations were used to calculate fuel-to- steam efficiencies. The listed efficiency accounts for loss up the stack , boiler radiation and convection losses.	
Date	06/20/18			
Author	John Boothby			
Customer	Moses Lake Industries			
City & State	Moses Lake, WA			
Boiler Model	CBEX Premium			
Design Pressure (psig)	150			
Furnace Volume (cuft)	124.60			
Heating Surface (sqft)	1128			
ENTHALPY				
Steam Enthalpy, hg (Btu/lb)	1191	1191	1191	1191
Feedwater Enthalpy, hfw (Btu/lb)	180	180	180	180
LOAD				
Operating BHP	**400**	**300**	**200**	**100**
Steam Flow Rate, (lbm/hr)	13,244	9,933	6,622	3,311
Firing Rate	**100%**	**75%**	**50%**	**25%**
Fuel Type	**Nat Gas**	**Nat Gas**	**Nat Gas**	**Nat Gas**
EXCESS AIR				
Excess Air Leaving Boiler	15.0%	15.0%	20.0%	20.0%
O2 Leaving Boiler	3.0%	3.0%	3.8%	3.8%
CO2 Leaving Boiler	10.0%	10.0%	9.6%	9.6%
PRESSURE				
Steam Operating Pressure, (psig)	110	110	110	110
TEMPERATURES				
Flue Gas Temp. Leaving Boiler (°F)	502	463	423	384
Feedwater Temperature, (°F)	212	212	212	212
Combustion Air Temperature (°F)	80	80	80	80
Steam Temperature (°F)	344	344	344	344
ENERGY				
Heat Output , (Btu/hr)	13,390,000	10,042,500	6,695,000	3,347,500
HHV Fuel-to-Steam Efficiency (%)	80.20	81.07	81.60	82.26
HHV Heat Input (Btu.hr)	16,696,436	12,386,728	8,204,683	4,069,421

Cleaver-Brooks Boiler Expected **Steam Performance Data** -

- -
30 - PPM Nox System

BACKGROUND INFORMATION				
Date	06/20/18		The ASME Power Test Code , PTC 4.1 Heat Loss Method equations were used to calculate fuel-to- steam efficiencies. The listed efficiency accounts for loss up the stack , boiler radiation and convection losses.	
Author	John Boothby			
Customer	Moses Lake Industries			
City & State	Moses Lake, WA			
Boiler Model	CBEX Premium			
Design Pressure (psig)	150			
Furnace Volume (cuft)	125			
Heating Surface (sqft)	1128			
HEAT LOSS				
Dry Gas (%)	7.94	7.20	6.76	5.98
H2 and H2O in Fuel (%)	11.60	11.43	11.26	11.08
Moisture in Air (%)	0.11	0.09	0.09	0.08
Radiation & Conv. (%)	0.15	0.20	0.30	0.60
Total Heat Loss (%)	19.80	18.93	18.40	17.74
FLOW RATES				
Gas LHV (Btu/SCF)	903	903	903	903
Gas HHV (Btu/SCF)	1000	1000	1000	1000
HHV Gas Flow Rate (SCFH)	16,696	12387	8,205	4069
Gas LHV (Btu/lb)	19,712	19712	19,712	19712
Gas HHV (Btu/lb)	21,830	21,830	21,830	21,830
Gas Flow Rate (lb/hr)	765	567	376	186
Dry Air Weight (lb/lb fuel)	18.15	18.15	18.94	18.94
Air for Combustion (lb/hr)	13,884	10,300	7,119	3,531
Flue Gas to Stack (lb/hr)	14,738	10,934	7,539	3,739
RESISTANCE				
Furnace Pressure (in WC)	5.33	2.93	1.39	0.34
Burner Press. Drop (in WC)	0.00	0.00	0.00	0.00
Net Resistance (in WC)	5.33	2.93	1.39	0.34
HEAT RELEASE				
Furnace Heat Release (Btu/hr/cuft)	134,000	99,412	65,848	32,660
Furnace Heat Release Rate (Btu/hr/sqft)	95,957	71,188	47,153	23,387
Heat Absorption Rate (Btu/hr/sqft)	11,871	8,903	5,935	2,968

Mr. Jason Herbst
Cole Industrial, Inc.
1502 S. 36th Avenue
Yakima, WA
98902

July 30th, 2018

Subject: Moses Lake Industries, CBEX Premium with E Series Burner
CB Quote #16490403
Methanol and Natural Gas Burner

Dear Mr. Herbst,

I have reviewed the above mentioned project. After this review, we guarantee emissions will not exceed 112 PPM NOx and 100 PPM CO based on the methanol analysis provided by Moses Lake Industries. Emissions when firing natural gas will not exceed 30 PPM NOx and 50 PPM CO.

All emissions are on a dry basis, corrected to 3% O2.

Do not hesitate to contact me if you have further questions.

Best regards,

Daniel D. Lefebvre, P. Eng.
Vice-President, Research & Development
Cleaver Brooks Burner Systems Group

APPENDIX F: MODELING FILES AND RESULTS

Appendix F. AERSCREEN Inputs and Results

Table F-1. AERSCREEN Source Parameters

Source ID	Modeled Emission Rate (g/s)	Source Elevation [a] (m)	Stack Height [b] (m)	Stack Diameter [b] (m)	Exhaust Temperature [c] (K)	Exhaust Velocity (m/s)	Flow Rate [d] (dcfm)	Flow Rate [d] (acfm)	Distance to Fenceline [e] (m)
Point	1	352.044	18.898	0.7112	487.04	4.78	2,424	4,027	62

[a] Approximate source elevation of 1155 ft from Simplified Site Plan, 2017 Emissions Report, provided by MLI.

[b] Stack height and diameter provided by MLI on June 12, 2018.

[c] Stack temperature based on average result for existing boiler while firing methanol (per 2017 source test); assumed to be conservative, given FGR design of new unit.

[d] The stack flow rate is based on the heat input capacity of the new 30 ppm NOx boiler at 100% firing rate, as provided in the Cole Industrial quote dated June 20, 2018. This heat input capacity is scaled by the F-factor for natural gas from EPA Method 19 (8,710 dscf/MMBtu) and converted to acfm based on the anticipated stack temperature. This calculation assumes the exhaust is at ambient pressure.

[e] Assume dscfm is at: 68 F 20 C

[f] The shortest distance from the stack to the fenceline was used, based on the two options provided by MLI on June 13, 2018.

Table F-2. AERSCREEN Modeling Results - TAPS

Source ID	Modeled Averaging Period	Maximum Modeled Concentration - Unit Emission Rate ($\mu g/m^3$)	Maximum Modeled NO2 Concentration[a] ($\mu g/m^3$)	ASIL ($\mu g/m^3$)	In Compliance with ASIL?
Point	1-hour	42.75	11.98	470	Yes

[a] The modeled results for the unit emission rate (1 g/s) were scaled by the new boiler's projected NO2 emission rate to assess compliance with the ASIL. For conservatism, all NOx is assumed to be NO2.

NO2 Emission Rate: 2.22 lb/hr
0.28 g/s

Table F-3. AERSCREEN Modeling Results - NAAQS

Pollutant	Modeled Averaging Period	Modeled Concentration - Unit Emission Rate ($\mu g/m^3$)	Modeled Concentration - Scaled Emission Rate[a] ($\mu g/m^3$)	Representative Background[b] ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	In Compliance with NAAQS?
NO2	1-hour	42.75	11.98	16.00	27.98	188	Yes
	annual	4.275	1.20	2.82	4.02	100	Yes
PM2.5	24-hour	25.65	0.40	14	14.40	35	Yes
	annual	4.275	0.07	5.3	5.37	12	Yes

[a] The modeled results for the unit emission rate (1 g/s) were scaled by the appropriate projected emission rate for the new boiler to assess compliance with the NAAQS.

NO2 Emission Rate: 2.22 lb/hr
0.28 g/s
PM2.5 Emission Rate: 0.12 lb/hr
0.02 g/s

[b] Per Ecology's suggestion, as communicated in a July 26th email from Jenny Filipy (Ecology) to Pat Blau (MLI), the following website was used to determine representative background concentrations for NO2 and PM2.5: http://lar.wsu.edu/nw-airquest/lookup.html
These results are based on the following facility location, expressed in latitude/longitude: 47.2051947, -119.2909225
Background values expressed in ppb were converted to ug/m3 by multiplying the concentration in ppb by the molecular weight and then dividing the result by (0.02447*1000).

APPENDIX G: REVISED PERMIT TABLE

Appendix G. Requested Changes to Emission Limits

> Condition 4.6 of Approval Order No. 16AQ-E022 establishes maximum annual emisssion limitations for the permitted sources at MLI's TMAC production facility.

> Table C5-1 documents these currently applicable emission limits.

> Table C5-2 identifies MLI's requested changes to these permit limits based on the proposed upgrade project and MLI's requested revision to the flare's methanol emission rate to better represent the system's current capacity. As described in Section C3, the requested change to the flare emission limit is unrelated to the project.

Table G-1. Summary of Current Permit Limits

	Source				
Pollutant	**Boiler**	**Flare**	**Fugitive**	**Total**	**Units**
NOx	7.5	6.99	--	14.5	tons/yr
CO	2.0	2.0	--	4.0	tons/yr
VOC (in actual weight)	1.79	6.49	12.52	20.80	tons/yr
TAPs (total)[a]	0.91	5.20	25.56	31.67	tons/yr
Methanol	1,740	1,422	11,621	14,783	lbs/yr
TMA[b]	20	5,000	3,000	8,020	lbs/yr

[a] During MLI's meeting with Ecology on June 15, 2018, Ecology discussed removing the TAPs (total) limit from the permit, as it is not necessary from a regulatory perspective.

[b] TMA is no longer a regulated TAP under WAC 173-460.

> To accommodate the proposed TMAC facility upgrade project, MLI proposes the following emission limits.

Table G-2. Proposed Permit Limits
****Changes Denoted in Bold Italics***

	Source					
Pollutant	**Boiler #1**	**Boiler #2[a]**	**Flare**	**Fugitive**	**Total**	**Units**
NOx	7.5	***6.17***	6.99	--	***20.7***	tons/yr
CO	2.0	***4.0***	2.0	--	***8.0***	tons/yr
VOC (in actual weight)	1.79	***0.94***	6.49	12.52	***21.74***	tons/yr
TAPs (total)[b]	**--**	--	**--**	**--**	**--**	--
Methanol[c]	1,740	***1,000***	***3,022***	***8,095***	***13,857***	lbs/yr
TMA[a,d]	20	***100***	***4,900***	3,000	8,020	lbs/yr

[a] Boiler #2 is a new emission unit associated with the proposed upgrade project. Therefore, all Boiler #2 table entries represent new permit limits.

[b] Based on Ecology's feedback during the June 15, 2018 meeting with MLI, MLI proposes removing the total TAPs limits from the permit.

[c] Potential fugitive emissions of methanol from piping components are conservatively quantified using the methodology described in Section C2 of this appendix. The result of this methodology represents a decrease of approximately 3,500 lbs/yr relative to the current permit limit for fugitive methanol emissions. As such, MLI requests that 1,600 lbs/yr of the current permit limit be reallocated to the flare to more accurately represent the flare's current emissions profile for the maximum TMAC production scenario. As described in Section C2, the requested increase to the flare's methanol emission limit is unrelated to the project. Furthermore, MLI requests that 1,000 lbs/yr of the current permit limit be reallocated to Boiler #2 to represent emission increases from the proposed project. This reallocation strategy ensures that facility-wide permitted methanol emissions do not increase as a result of the upgrade project or flare limit adjustment.

[d] TMA is no longer a regulated TAP under WAC 173-460. As such, MLI would be supportive of Ecology removing TMA limits from the permit. However, MLI has included proposed TMA limits in this table to be comprehensive. MLI proposes that 100 lbs/yr of TMA emissions currently allocated to the flare be reallocated to Boiler #2 to represent emission increases from the proposed project. Due to the process improvements associated with the proposed upgrade project, the actual flare venting rate is expected to decrease at the facility's maximum TMAC production rate. Consequently, even at the maximum anticipated TMAC production rate, MLI will be able to demonstrate compliance with this reduced TMA limit for the flare. This reallocation strategy ensures that facility-wide permitted TMA emissions do not increase as a result of the upgrade project.

APPENDIX H: SEPA CHECKLIST

SEPA ENVIRONMENTAL CHECKLIST

Purpose of checklist:

Governmental agencies use this checklist to help determine whether the environmental impacts of your proposal are significant. This information is also helpful to determine if available avoidance, minimization or compensatory mitigation measures will address the probable significant impacts or if an environmental impact statement will be prepared to further analyze the proposal.

Instructions for applicants:

This environmental checklist asks you to describe some basic information about your proposal. Please answer each question accurately and carefully, to the best of your knowledge. You may need to consult with an agency specialist or private consultant for some questions. You may use “not applicable” or "does not apply" only when you can explain why it does not apply and not when the answer is unknown. You may also attach or incorporate by reference additional studies reports. Complete and accurate answers to these questions often avoid delays with the SEPA process as well as later in the decision-making process.

The checklist questions apply to all parts of your proposal, even if you plan to do them over a period of time or on different parcels of land. Attach any additional information that will help describe your proposal or its environmental effects. The agency to which you submit this checklist may ask you to explain your answers or provide additional information reasonably related to determining if there may be significant adverse impact.

Instructions for Lead Agencies:

Please adjust the format of this template as needed. Additional information may be necessary to evaluate the existing environment, all interrelated aspects of the proposal and an analysis of adverse impacts. The checklist is considered the first but not necessarily the only source of information needed to make an adequate threshold determination. Once a threshold determination is made, the lead agency is responsible for the completeness and accuracy of the checklist and other supporting documents.

Use of checklist for nonproject proposals:

For nonproject proposals (such as ordinances, regulations, plans and programs), complete the applicable parts of sections A and B plus the SUPPLEMENTAL SHEET FOR NONPROJECT ACTIONS (part D). Please completely answer all questions that apply and note that the words "project," "applicant," and "property or site" should be read as "proposal," "proponent," and "affected geographic area," respectively. The lead agency may exclude (for non-projects) questions in Part B - Environmental Elements –that do not contribute meaningfully to the analysis of the proposal.

A. Background [HELP]

1. Name of proposed project, if applicable:

   TMAC Product Quality/Emissions Upgrade and New #2 Boiler

2. Name of applicant: **Moses Lake Industries**

3. Address and phone number of applicant and contact person:

Moses Lake Industries

8245 Randolph Road NE

Moses Lake, WA 98837

Attn: Pat Blau 509-762-5336 x 236

4. Date checklist prepared: **6/13/2018**

5. Agency requesting checklist: **Washington State Department of Ecology (WDOE)**

6. Proposed timing or schedule (including phasing, if applicable): **Fall 2018 though 2019**

7. Do you have any plans for future additions, expansion, or further activity related to or connected with this proposal? If yes, explain. **No.**

8. List any environmental information you know about that has been prepared, or will be prepared, directly related to this proposal.

- This SEPA checklist and the WDOE Notice of Construction air permit application

9. Do you know whether applications are pending for governmental approvals of other proposals directly affecting the property covered by your proposal? If yes, explain.

No.

10. List any government approvals or permits that will be needed for your proposal, if known.
WDOE Notice of Construction and updated approval order. Buildling permits.

11. Give brief, complete description of your proposal, including the proposed uses and the size of the project and site. There are several questions later in this checklist that ask you to describe certain aspects of your proposal. You do not need to repeat those answers on this page. (Lead agencies may modify this form to include additional specific information on project description.)
- The project consists up upgrades to TMAC manufacturing operation to improve product quality and reduce potential emisions. Items include the raw material purification section, utility chiller support, reactor vessel re-arrangement, distillation column packing and vent condenser systems. A new utility #2 Boiler is proposed to support the line.

12. Location of the proposal. Give sufficient information for a person to understand the precise location of your proposed project, including a street address, if any, and section, township, and range, if known. If a proposal would occur over a range of area, provide the range or boundaries of the site(s). Provide a legal description, site plan, vicinity map, and topographic map, if reasonably available. While you should submit any plans required by the agency, you are not required to duplicate maps or detailed plans submitted with any permit applications related to this checklist.

Moses Lake Industries

8245 Randolph Road NE
Moses Lake, WA 98837

B. Environmental Elements [HELP]

1. *Earth* [help]

a. General description of the site:

(circle one): Flat, rolling, hilly, steep slopes, mountainous, other _____________

Generally Flat, slight rolling slopes in some cases.

b. What is the steepest slope on the site (approximate percent slope)?

5%

c. What general types of soils are found on the site (for example, clay, sand, gravel, peat, muck)? If you know the classification of agricultural soils, specify them and note any agricultural land of long-term commercial significance and whether the proposal results in removing any of these soils.

Soils are a mixture of sandy, loam and gravel/cobbles in various layers.

d. Are there surface indications or history of unstable soils in the immediate vicinity? If so, describe. **No.**

e. Describe the purpose, type, total area, and approximate quantities and total affected area of any filling, excavation, and grading proposed. Indicate source of fill. **Minor amounts of grading of existing soils for the new Boiler #2 location. Assume maximum 50 x 100 feet equivalent area.**

f. Could erosion occur as a result of clearing, construction, or use? If so, generally describe.
No.

g. About what percent of the site will be covered with impervious surfaces after project construction (for example, asphalt or buildings)?

The project will not make a significant change to overall site impervious surface. The new boiler building will be approximately 25 x 35 feet.

h. Proposed measures to reduce or control erosion, or other impacts to the earth, if any:
No impacts are expected due to the minor amount of grading on a flat area of the plant.

2. Air [help]

a. What types of emissions to the air would result from the proposal during construction, operation, and maintenance when the project is completed? If any, generally describe and give approximate quantities if known.
No significant emissions are expected during construction. The upgrades to the TMAC plant will reduce existing potential emissions. The new Boiler #2 will generate minor amounts of combustion emissions which will be limited by the application of Best Available Control Technology (BACT) burner equipment.

b. Are there any off-site sources of emissions or odor that may affect your proposal? If so, generally describe.
None.

c. Proposed measures to reduce or control emissions or other impacts to air, if any:
The TMAC portion of the project is already designed to reduce the level of existing potential air emissions. BACT level equipment for the new Boiler #2.

3. Water [help]

a. Surface Water: [help]

1) Is there any surface water body on or in the immediate vicinity of the site (including year-round and seasonal streams, saltwater, lakes, ponds, wetlands)? If yes, describe type and provide names. If appropriate, state what stream or river it flows into.

No. The closest surface water body is Crab Creek some 2 miles to the east.

2) Will the project require any work over, in, or adjacent to (within 200 feet) the described waters? If yes, please describe and attach available plans.

No

3) Estimate the amount of fill and dredge material that would be placed in or removed from surface water or wetlands and indicate the area of the site that would be affected. Indicate the source of fill material.

None. Does not apply.

4) Will the proposal require surface water withdrawals or diversions? Give general description, purpose, and approximate quantities if known.

No.

5) Does the proposal lie within a 100-year floodplain? If so, note location on the site plan.

No.

6) Does the proposal involve any discharges of waste materials to surface waters? If so, describe the type of waste and anticipated volume of discharge.

No.

b. Ground Water: [help]

1) Will groundwater be withdrawn from a well for drinking water or other purposes? If so, give a general description of the well, proposed uses and approximate quantities withdrawn from the well. Will water be discharged to groundwater? Give general description, purpose, and approximate quantities if known.

No. Moses Lake Industries is already supplied with potable water supply from the City of Moses Lake.

2) Describe waste material that will be discharged into the ground from septic tanks or other sources, if any (for example: Domestic sewage; industrial, containing the following chemicals. . . ; agricultural; etc.). Describe the general size of the system, the number of such systems, the number of houses to be served (if applicable), or the number of animals or humans the system(s) are expected to serve.

No waste material will be discharged into the ground from this project.

c. Water runoff (including stormwater):

1) Describe the source of runoff (including storm water) and method of collection and disposal, if any (include quantities, if known). Where will this water flow? Will this water flow into other waters? If so, describe.

A minor amount of stormwater will be generated from the impervious surface associated with the new #2 Boiler Building (area of approximately 25 x 35 feet). This water will runoff to adjacent gravel area.

2) Could waste materials enter ground or surface waters? If so, generally describe.

No.

3) Does the proposal alter or otherwise affect drainage patterns in the vicinity of the site? If so, describe.

No.

d. Proposed measures to reduce or control surface, ground, and runoff water, and drainage pattern impacts, if any:

None required.

4. Plants [help]

a. Check the types of vegetation found on the site:

____deciduous tree: alder, maple, aspen, other
____evergreen tree: fir, cedar, pine, other
____shrubs
_**X**__grass
____pasture
____crop or grain
____ Orchards, vineyards or other permanent crops.
____ wet soil plants: cattail, buttercup, bullrush, skunk cabbage, other
____water plants: water lily, eelgrass, milfoil, other

____other types of vegetation

b. What kind and amount of vegetation will be removed or altered?

None. The minor area to be disturbed is already a graveled parking area.

c. List threatened and endangered species known to be on or near the site.

None.

d. Proposed landscaping, use of native plants, or other measures to preserve or enhance vegetation on the site, if any:

None – Does not apply.

e. List all noxious weeds and invasive species known to be on or near the site.

None.

5. Animals [help]

a. List any birds and other animals which have been observed on or near the site or are known to be on or near the site.

Examples include:

birds: hawk, heron, eagle, songbirds, other:
mammals: deer, bear, elk, beaver, other:
fish: bass, salmon, trout, herring, shellfish, other ________

Unknown quanties of birds and small mammals have been observed in outer areas of the plant site. None in the actual work area.

b. List any threatened and endangered species known to be on or near the site.

None.

c. Is the site part of a migration route? If so, explain.

Generally, the site is in the Pacific Flyway. However this site has not historically been a known landing site.

d. Proposed measures to preserve or enhance wildlife, if any:

N/A

e. List any invasive animal species known to be on or near the site.

None.

6. Energy and Natural Resources [help]

a. What kinds of energy (electric, natural gas, oil, wood stove, solar) will be used to meet the completed project's energy needs? Describe whether it will be used for heating, manufacturing, etc.

The project will use electricity for lighting and equipment operation and natural gas for heating.

b. Would your project affect the potential use of solar energy by adjacent properties? If so, generally describe.
No.

c. What kinds of energy conservation features are included in the plans of this proposal? List other proposed measures to reduce or control energy impacts, if any:

Does not apply.

7. Environmental Health [help]

a. Are there any environmental health hazards, including exposure to toxic chemicals, risk of fire and explosion, spill, or hazardous waste, that could occur as a result of this proposal? If so, describe.

1) Describe any known or possible contamination at the site from present or past uses.
None known.

2) Describe existing hazardous chemicals/conditions that might affect project development and design. This includes underground hazardous liquid and gas transmission pipelines located within the project area and in the vicinity.
The project is an upgrade to an existing chemical manufacturing operation and will add no new hazards.

3) Describe any toxic or hazardous chemicals that might be stored, used, or produced during the project's development or construction, or at any time during the operating life of the project.
Existing quantities of raw material, process and product materials will not appreciably change. Materials are already handled within secondary containment to prevent or collect any spill.

4) Describe special emergency services that might be required.
None. Existing emergency services currently available are adequate.

5) Proposed measures to reduce or control environmental health hazards, if any:
New equipment within the TMAC area will be installed following Process Safety Management Guidelines.

b. Noise

1) What types of noise exist in the area which may affect your project (for example: traffic, equipment, operation, other)?
None. The existing manufacturing equipment noise will not appreciably change.

2) What types and levels of noise would be created by or associated with the project on a short-term or a long-term basis (for example: traffic, construction, operation, other)? Indicate what hours noise would come from the site.

Minor amounts of noise onsite during construction will not appreciably change existing noise levels.

3) Proposed measures to reduce or control noise impacts, if any:

Does not apply.

8. Land and Shoreline Use [help]

a. What is the current use of the site and adjacent properties? Will the proposal affect current land uses on nearby or adjacent properties? If so, describe.

No.

b. Has the project site been used as working farmlands or working forest lands? If so, describe. How much agricultural or forest land of long-term commercial significance will be converted to other uses as a result of the proposal, if any? If resource lands have not been designated, how many acres in farmland or forest land tax status will be converted to nonfarm or nonforest use?

N/A – The project site has not been used as working farmland or forest land.

1) Will the proposal affect or be affected by surrounding working farm or forest land normal business operations, such as oversize equipment access, the application of pesticides, tilling, and harvesting? If so, how:

No.

c. Describe any structures on the site.

The Moses Lake Industries manufacturing site already has some 15 structions on-site.

d. Will any structures be demolished? If so, what?

No.

e. What is the current zoning classification of the site?

Heavy Industrial.

f. What is the current comprehensive plan designation of the site?

Industrial Use.

g. If applicable, what is the current shoreline master program designation of the site?

N/A

h. Has any part of the site been classified as a critical area by the city or county? If so, specify.

No.

i. Approximately how many people would reside or work in the completed project?

None. The existing staffing levels for the TMAC department will not change.

j. Approximately how many people would the completed project displace?

None.

k. Proposed measures to avoid or reduce displacement impacts, if any:

N/A

L. Proposed measures to ensure the proposal is compatible with existing and projected land uses and plans, if any:

N/A

m. Proposed measures to reduce or control impacts to agricultural and forest lands of long-term commercial significance, if any:

N/A

9. Housing [help]

a. Approximately how many units would be provided, if any? Indicate whether high, middle, or low-income housing.

None.

b. Approximately how many units, if any, would be eliminated? Indicate whether high, middle, or low-income housing.

None.

c. Proposed measures to reduce or control housing impacts, if any:

Does not apply.

10. Aesthetics [help]

a. What is the tallest height of any proposed structure(s), not including antennas; what is the principal exterior building material(s) proposed?

The new #2 Boiler stack will be 62' tall and 28" diameter. This is shorter than the existing boiler stack which is 75' tall. The boiler building exterior will be painted metal.

b. What views in the immediate vicinity would be altered or obstructed?

None.

c. Proposed measures to reduce or control aesthetic impacts, if any:

N/A

11. Light and Glare [help]

a. What type of light or glare will the proposal produce? What time of day would it mainly occur?

No significant glare will be generated. The new #2 Boiler structure will have similar lighting to the existing structures.

b. Could light or glare from the finished project be a safety hazard or interfere with views?

No.

c. What existing off-site sources of light or glare may affect your proposal?

No.

d. Proposed measures to reduce or control light and glare impacts, if any:

Does not apply.

12. Recreation [help]

a. What designated and informal recreational opportunities are in the immediate vicinity?

None.

b. Would the proposed project displace any existing recreational uses? If so, describe.

No.

c. Proposed measures to reduce or control impacts on recreation, including recreation opportunities to be provided by the project or applicant, if any:

Does not apply.

13. Historic and cultural preservation [help]

a. Are there any buildings, structures, or sites, located on or near the site that are over 45 years old listed in or eligible for listing in national, state, or local preservation registers ? If so, specifically describe.

No.

b. Are there any landmarks, features, or other evidence of Indian or historic use or occupation? This may include human burials or old cemeteries. Are there any material evidence, artifacts, or areas of cultural importance on or near the site? Please list any professional studies conducted at the site to identify such resources.

No.

c. Describe the methods used to assess the potential impacts to cultural and historic resources on or near the project site. Examples include consultation with tribes and the department of archeology and historic preservation, archaeological surveys, historic maps, GIS data, etc.

Does not apply.

d. Proposed measures to avoid, minimize, or compensate for loss, changes to, and disturbance to resources. Please include plans for the above and any permits that may be required.

Does not apply.

14. Transportation [help]

a. Identify public streets and highways serving the site or affected geographic area and describe proposed access to the existing street system. Show on site plans, if any.

Randalph Road provides service to the existing Moses Lake Industries site.

b. Is the site or affected geographic area currently served by public transit? If so, generally describe. If not, what is the approximate distance to the nearest transit stop?

No.

c. How many additional parking spaces would the completed project or non-project proposal have? How many would the project or proposal eliminate?

None.

d. Will the proposal require any new or improvements to existing roads, streets, pedestrian, bicycle or state transportation facilities, not including driveways? If so, generally describe (indicate whether public or private).

NO.

e. Will the project or proposal use (or occur in the immediate vicinity of) water, rail, or air transportation? If so, generally describe.

No.

f. How many vehicular trips per day would be generated by the completed project or proposal? If known, indicate when peak volumes would occur and what percentage of the volume would be trucks (such as commercial and nonpassenger vehicles). What data or transportation models were used to make these estimates?

One to two truck loads per day. This will not appreciably change existing site truck traffic.

g. Will the proposal interfere with, affect or be affected by the movement of agricultural and forest products on roads or streets in the area? If so, generally describe.

No.

h. Proposed measures to reduce or control transportation impacts, if any:

Does not apply.

15. Public Services [help]

a. Would the project result in an increased need for public services (for example: fire protection, police protection, public transit, health care, schools, other)? If so, generally describe.

No.

b. Proposed measures to reduce or control direct impacts on public services, if any.

Does not apply.

16. Utilities [help]

a. Circle utilities currently available at the site:
electricity, natural gas, water, refuse service, telephone, sanitary sewer, septic system, other ___________

All of the above, except septic sewer.

d. Describe the utilities that are proposed for the project, the utility providing the service, and the general construction activities on the site or in the immediate vicinity which might be needed.

Existing utilities already available onsite at Moses Lake Industries will be adequate.

C. Signature [HELP]

The above answers are true and complete to the best of my knowledge. I understand that the lead agency is relying on them to make its decision.

Signature: ____

Name of signee ___Patrick J. Blau____

Position and Agency/Organization _____EHSS Manager______________________________

Date Submitted: ____________

for the protection of the environment.