Technical Analysis Report
For the terms and conditions of
Construction Permit AQ0934CPT02

Issued to Donlin Gold LLC

For the Donlin Gold Project

Alaska Department of Environmental Conservation
Air Permits Program

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Abbreviations/Acronyms

AAC ....Alaska Administrative Code
AAAQS ....Alaska Ambient Air Quality Standards
ANFO ....ammonium nitrate and fuel oil
BACT ....Best Available Control Technology
CAA ....Clean Air Act
CCD...............................counter-current decantation
C.F.R. ....Code of Federal Regulations
CIL ....carbon-in-leach
Department ....Alaska Department of Environmental Conservation
DGP ....Donlin Gold Project
DLN..............................Dry Low NOx
EPA ....Environmental Protection Agency
EU.................................Emission Unit
EU ID ....Emissions Unit Identification
HAP ....Hazardous Air Pollutant
MCF2 ....mill-chemical-float-mill-chemical-float
MR&R ....Monitoring, Recording, and Reporting
NA ....Not Applicable
NESHAPS ....National Emission Standards for Hazardous Air Pollutants
NSPS ....New Source Performance Standards
ORL ....Owner Requested Limit
POX ....pressure oxidation
PSD...............................Prevention of Significant Deterioration
PTE...............................Potential to Emit
RICE, ICE ....Reciprocating Internal Combustion Engine, Internal Combustion Engine
SAG ....semi-autogenous grinding
SCR ....Selective Catalytic Reduction
SIP ....Alaska State Implementation Plan
TAR ....Technical Analysis Report
ULSD ....Ultra Low Sulfur Diesel
VE.................................Visible Emissions

Units and Measures

gal/hr.............................gallons per hour
g/kWh ....grams per kilowatt hour
g/hphr ....grams per horsepower hour
hr/day.............................hours per day
hr/yr ....hours per year
hp..................................horsepower
lb/hr ....pounds per hour
lb/MMBtu......................pounds per million British thermal units
lb/1000 gal.....................pounds per 1,000 gallons
kW ....kilowatts
MMBtu/hr......................million British thermal units per hour
MMscf/hr.......................million standard cubic feet per hour
ppmv..............................parts per million by volume
tpy.................................tons per year

Pollutants

CO ....Carbon Monoxide
CO_2e ....Carbon Dioxide Equivalent
GHG ....Greenhouse Gases
HAP ....Hazardous Air Pollutant
NOx ....Oxides of Nitrogen
NO_2...............................nitrogen dioxide
PM ....Particulate Matter
$PM_{2.5}$.............................Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM_{10} ....Particulate Matter with an aerodynamic diameter not exceeding 10 microns
SO_2 ....Sulfur Dioxide
VOC ....Volatile Organic Compound

1. INTRODUCTION

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Air Quality Control Construction Permit AQ0934CPT02 to Donlin Gold LLC (Donlin) for their Donlin Gold Project (DGP). The project triggers Prevention of Significant Deterioration (PSD) review under 18 AAC 50.306 for oxides of nitrogen (NOx), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter not exceeding 10 microns (PM_{10}), particulate matter with an aerodynamic diameter not exceeding 2.5 microns ($PM_{2.5}$), volatile organic compounds (VOCs), and greenhouse gases (GHGs). This project is classified under 18 AAC 50.502(b)(3) for the construction, operation, or relocation of a stationary source containing a rock crusher with a rated capacity of at least five tons per hour. The project also includes an Owner Requested Limit (ORL) under 18 AAC 50.508(5) to avoid PSD review for sulfur dioxide (SO_2) and to avoid Hazardous Air Pollutants major classification.

1.1 Description of Source

The DGP is an existing stationary source located on the western slopes of the Kuskokwim Mountains in the Yukon-Kuskokwim region of southwestern Alaska, approximately 280 miles west of Anchorage. The facility is classified under Standard Industrial Classification code 1041 for Metal Mining/Gold Ores and under North American Industrial Classification code 212221 for Gold Ore Mining.

Donlin currently has authority to operate the stationary source under Construction Permit AQ0934CPT01 issued June 30, 2017. However, the stationary source has yet to commence construction and has been issued 18-month PSD extension approvals by the Department on October 12, 2018, May 15, 2020, and December 1, 2021. The third and final PSD extension approval requires Donlin to commence construction no later than June 30, 2023.

1.2 Application Description

Donlin submitted an application for this project on October 29, 2021 and submitted several addenda through May 6, 2022. Donlin is requesting authorization to install and operate the same EUs contained in Construction Permit AQ0934CPT01, including reciprocating internal combustion engines, boilers, heaters, autoclaves, incinerators, a gyratory crusher, a pebble crusher, carbon regeneration kilns, electrowinning circuit cells, a smelting furnace, a mercury retort, laboratories, and a tank farm to support gold mining and processing.

1.3 Project Description

The DGP deposit consists of two main areas, ACMA and Lewis, which will ultimately be mined as a single open pit. These areas have similar mineralization characteristics, with ore-grade gold hosted in both intrusive and sedimentary rock units. The mine and process operations will operate on a continuous, 24-hour-per-day basis. In addition to the mining operations, Donlin will be constructing a natural gas pipeline, a power generation facility, an onsite employee accommodation complex, roads, ports, shipping and barging infrastructure, and an airstrip. This permitting action covers only the mining and processing operations, power generation facility, haul roads, camp to mine site access road, airport to camp access road, and emission units supporting the onsite employee accommodation complex and airstrip.

Mining operations at DGP include surveying and drilling of blast holes. Donlin will use an ammonium nitrate and fuel oil (ANFO)-based explosive emulsion for blasting. Ore and waste will be loaded by front-end loaders and hydraulic shovels into end-dump haul trucks. The trucks will haul the waste rock to the waste rock facility while ore will be hauled to the gyratory crusher. From the trucks the ore will be directly fed to the gyratory crusher dump pocket with a rock breaker or stockpiled. Alternatively, the ore could be hauled to a long-term ore stockpile before being taken to the gyratory crusher.

Ore will be discharged from the gyratory crusher dump pocket onto the discharge conveyor and transferred to the stockpile feed conveyor where it will be discharged onto a covered coarse ore stockpile. The course ore will be transferred via four reclaim apron feeders to the semi-autogenous grinding (SAG) mill feed conveyor for transport to the SAG mill.

Donlin will utilize an open circuit SAG mill followed by a “mill-chemical-float-mill-chemical-float” (MCF2) circuit for the grinding process. Copper sulfate will be added to the SAG mill feed to activate sulfide mineralization. Discharge from the SAG mill will be screened to send oversized pebbles to two large cone pebble crushers. The oversized pebbles will be returned to the SAG mill feed via conveyors after passing through the pebble crushers. The MCF2 circuit following the SAG mill will consist of a primary ball mill and primary rougher flotation followed by a secondary ball mill, secondary rougher flotation, and thickening.

During this process several reagents, such as acidic solution from the pressure oxidation (POX) counter-current decantation (CCD) washing circuit, lime, copper sulfate, potassium amyl xanthate, soda ash, caustic soda, flocculants, dispersants, and frothers, will be added to condition the concentration slurry. Donlin will install associated process equipment for reagent handling and mixing.

The thickener concentrate from the MCF2 process will proceed to an acidulation circuit. Acidic solution recovered from the POX CCD washing circuit will be added to the concentrate slurry to reduce the carbonate gangue component. The acidulated concentrate slurry will be washed in a three-thickener CCD circuit to remove chlorides and pumped to the POX circuit.

Concentrate POX is carried out in one of two autoclaves operating in parallel. High-pressure steam will be supplied to the process when needed by two dual-fuel POX boilers. The dual-fuel oxygen plant boiler will provide high pressure oxygen gas for the POX reaction. Discharge from the autoclaves will be sent to flash vessels to depressurize the autoclaved concentrate slurry. The slurry will then be transferred to three POX hot cure tanks.

After the POX circuit the concentrate slurry will be washed in a four-thickener CCD circuit. Washed concentrate slurry in the underflow from the final thickener will be pumped to the CIL solids neutralization circuit and the overflow will be clarified and used within the plant to provide acidification to the acidulation circuit. The CIL neutralization circuit will consist of mechanically agitated tanks where lime slurry will be added to the concentrate slurry in the presence of oxygen to bring the pH to approximately 9 before being pumped to the CIL circuit.

The carbon-in-leach (CIL) circuit will consist of six CIL tanks that will hold the concentrate slurry for four hours. Here a sodium cyanide solution will be pumped into the CIL circuit for cyanide leaching. Lime slurry and caustic soda will be added to maintain a pH of approximately 10.5.

After the CIL circuit will be the cyanide destruction system which include an agitated tank where compressed air and gaseous SO_2 generated in the SO_2 burner will be added to oxidize the residual cyanide. Copper sulfate solution will be added to maintain the reaction kinetics and lime slurry will be used to maintain the pH level.

The loaded carbon from the CIL circuit will then be washed with a 3 percent nitric acid solution, neutralized with a caustic solution in two acid wash vessels, and pumped to two strip vessels. A solution of 1 percent sodium hydroxide and 1 percent sodium cyanide will be added to the strip vessels to strip the gold adsorbed on the carbon. The dual-fuel carbon elution heater will provide the hot glycol solution for the heat exchanger that the pregnant solution passes through after the strip vessels. The stripped carbon will be washed and sent to the carbon regeneration kiln for reuse in the CIL circuit, and the pregnant solution will be sent to the pregnant solution tank.

The pregnant solution will then be pumped through two parallel trains of electrowinning cells to remove the precious metals. The remaining solution will be sent to the barren solution tanks for recirculation through the strip vessels. The precious metal bearing sludge from the electrowinning circuit will be washed, press-filtered, and loaded into the mercury retort. Here it will be electrically heated for 12 hours to remove mercury. After the mercury retort, the sludge will be mixed with smelting fluxes and charged to the induction smelting furnace. Doré bars will be poured from the smelting furnace and shipped offsite for additional refining.

Donlin will generate electric power from a dual-fuel reciprocating engine onsite power plant with a steam turbine utilizing waste heat recovered from the engines (combined cycle power plant). The power plant will consist of 12 Wärtsilä model 18V50DF engines rated at 17 MW each, a steam turbine rated at 15 MW (gross), two black start ULSD generators rated at 600 kW (used to restore power plant operations if there is a plant shutdown), two ULSD fired engines rated at 200 kW each will be used to power the airstrip and associated operations, four ULSD-fired emergency generators rated at approximately 1,500 kW each will be used to provide power to the camp site during emergency situation, and three ULSD-fired fire pump engines rated at approximately 252 hp each for safety and emergency situations.

Additional units include SO_2 burners, heaters, building space heating, a water conditioning system, a camp waste incinerator, a sewage sludge incinerator, a sample preparation laboratory, an assay analysis laboratory, a metallurgical analysis laboratory, and multiple fuel tanks.

1.4 PSD Description

The basic elements of the PSD program may be found in Title I, Part C of the Clean Air Act (CAA). Congress developed the program to protect public health, preserve, protect, and enhance air quality in national areas of interest, ensure that economic growth will occur in a manner consistent with the preservation of existing clean air resources and ensure permitting decisions are made after careful evaluation of all consequences.

EPA promulgated the detailed requirements in 40 C.F.R. 51.166 (PSD requirements within a State Implementation Plan) and 40 C.F.R. 52.21 (federal implementation of the PSD program). The Department has adopted the various aspects of the federal PSD program by reference in 18 AAC 50.040(h), and requires PSD applicants to follow those provisions, except as noted, in 18 AAC 50.306.

40 C.F.R. 52.21(b)(1) of the federal PSD regulations defines a "major stationary source" as either (a) any of 28 designated stationary source categories with potential emissions of 100 tons per year (tpy) or more of any regulated attainment pollutant, (b) any other stationary source with potential emissions of 250 tpy or more of any regulated attainment pollutant, or (c) any physical change that would occur at a stationary source that would constitute a major stationary source by itself.

In addition, once a new stationary source has been determined to be a "major" source, it is subject to PSD review for each regulated attainment pollutant that the source would have the potential to emit in "significant" amounts, which in some cases is lower than the "major" thresholds. 40 C.F.R. 52.21(b)(50)(iv) includes pollutants "subject to regulation" as defined in 40 C.F.R. 52.21(b)(49) as regulated pollutants. For this project, Greenhouse Gas (GHG) emissions become a regulated pollutant if the project's total GHG emissions on a CO_2e basis equal or exceed 75,000 tpy.

1.5 Jungjuk Port and Port to Mine Access Road

Donlin intends to construct a port along the Kuskokwim River near Jungjuk Creek/Angyaruaq to support DGP. The Department determined on July 16, 2014 that the mine and port sites are separate stationary sources for air quality permitting purposes. The port emissions are therefore not included, nor authorized, in Construction Permit AQ0934CPT02. Donlin will need to submit a separate air quality permit application, *if warranted*, to seek Department approval to construct and operate the port site.

Donlin intends to construct a 28-mile-long access road between the Jungjuk port and mine site (EU ID 162) to transport the cargo and supplies needed for DGP which is included in this permit. Donlin is required to control the fugitive dust emissions for the access road under 18 AAC 50.045(d).

2. EMISSIONS SUMMARY AND PERMIT APPLICABILITY

2.1. Emissions Summary and Permit Applicability

Donlin is proposing to construct the DGP stationary source as a PSD "major stationary source" under 40 C.F.R. 52.21(b)(1)(i)(b), with potential emissions of 250 tons per year or more of a single regulated NSR pollutant. Potential emissions from the proposed project are significant for seven different PSD pollutants: NOx, CO, PM, PM_{10}, $PM_{2.5}$, VOC, and GHG.

Table 1 lists total facility potential to emit[1] (PTE) relative to the PSD major source thresholds under 40 C.F.R. 52.21(b)(1)(i)(b) and the significant emissions rates under 40 C.F.R. 52.21(b)(23)(i) and 40 C.F.R. 52.21(b)(49)(iii) for PSD regulated pollutants. Fugitive emissions are not included in determining major stationary source status, per 40 C.F.R. 52.21(b)(1)(iii). However, fugitive emissions are included when comparing the project emissions to the significant emission rates.

Table 1: Major Source and PSD Review Applicability

Description	CO	NOx	$PM_{2.5}$	PM_{10}	PM	SO_2	VOC	CO_2e[1]
PTE for AQ0934CPT02 excluding fugitive emissions	1,325.2	1,537.4	597.8.3	601.5	606.4	23.2	1,148.3	1,731,120
Major Source Threshold	250	250	250	250	250	250	250	N/A
Major Source Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**No**
PTE for AQ0934CPT02 including fugitive emissions	3,246.2	1,589.0	811.7	2,003.3	5,406.7	23.4	1,148.3	1,742,900
PSD Significant Emissions Rates	100	40	10[2]	15	25	40	40[3]	75,000
PSD Review Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**Yes**

Table Notes:

1. GHGs are subject to regulation because the stationary source is major for a non-GHG pollutant and the CO_2e is at least 75,000 tpy.
2. PSD review for $PM_{2.5}$ can also be triggered by NOx and SO_2 precursor emissions, as specified under 40 C.F.R. 52.21(b)(23)(i).
3. VOC acts as a surrogate for ozone (O_3). In addition to the VOC emissions trigger, PSD review for O_3 can also be triggered by NOx emissions, as specified under 40 C.F.R. 52.21(b)(23)(i).

CO, NOx, $PM_{2.5}$, PM_{10}, PM, and VOC emissions are all over the 250 ton per year major source threshold found in 40 C.F.R. 52.21(b)(1)(i)(b), therefore the source is subject to PSD review for each regulated NSR pollutant where the PTE is at least the significant emission rate. As shown in

[1] PTE for the DGP were determined based on the maximum emission rates for the life of the mine.

Table 1, SO_2 is the only NSR pollutant not subject to PSD review.

Table 2 shows a summary of the project's PTE for CO, NOx, $PM_{2.5}$, PM_{10}, PM, VOC, and SO_2 for determining assessable emissions. Fugitive emissions are included in Table 2. Detailed emissions calculations are included in Appendix A.

Table 2: Emissions from Stationary EUs at DGP, Tons per Year

Description	CO	NOx	$PM_{2.5}$	PM_{10}	PM	SO_2	VOC
PTE for AQ0934CPT02	3,246.2	1,589.0	811.7	2,003.3	5,406.7	23.4	1,148.3
Assessable Emissions[1]	**3,246**	**1,589**	**N/A[2]**	**N/A[2]**	**5,407**	**23**	**1,148**
	11,413						

Table Notes:

1. Camp EUs are not included in assessable emissions because they will be operated for a limited time as described in Section 2.2.
2. PM emissions include PM_{10} and $PM_{2.5}$ emissions. Therefore, PM_{10} and $PM_{2.5}$ are not counted in total assessable emissions.

Donlin's total assessable emissions for the stationary source are 11,413 tpy. Donlin's application shows that the source's PTE for combined hazardous air pollutants (HAPs) are 22.1 tpy with the highest PTE for an individual HAP (formaldehyde) of 9.9 tpy.

2.2. Department Findings

Based on the review of the application, the Department finds that:

1. The DGP is classified as a major stationary source under 40 C.F.R. 52.21(b)(1)(i)(b) because the stationary source has the potential to emit at least 250 tpy of a single regulated NSR air pollutant. The GHGs are subject to regulation per 40 C.F.R. 52.21(b)(49)(iv)(a). Therefore, the project requires a PSD permit under 18 AAC 50.306(a) for these pollutants.
2. The Department included three mobile sources (water truck, grader, and dozer) in the emission unit inventory table of AQ0934CPT02. The tail pipe emissions of these mobile sources are not regulated under AQ0934CPT02. However, these mobile sources are sources of fugitive dust and those emissions are included for permit applicability and assessable emissions.
3. Because Donlin is requesting ORLs, the project is also classified under 18 AAC 50.508(5). This project is additionally classified under 18 AAC 50.502(b)(3) for the construction, operation, or relocation of a stationary source containing a rock crusher with a rated capacity of at least five tons per hour.
4. The project does not trigger a minor permit under 18 AAC50.502(c) for SO_2.
5. The Department included a previous limit from AQ0934CPT01 that required Donlin to use ULSD as fuel for any diesel fuel burning equipment to avoid PSD review for SO_2. The Department has included the previous conditions to comply with the SO_2 limit. The Department included both an operational limit and a tpy limit consistent with EPA policy on limiting PTE.
6. Donlin requested an emission limit for formaldehyde on EU IDs 1 through 12 to avoid classification as a HAPs major stationary source. The Department included both an operational limit and a tpy limit consistent with EPA policy on limiting PTE. The operational limit includes conditions for installation, operation, and maintenance of an oxidation catalyst to comply with the requested emission limit. The Department also

included an initial source test requirement while firing natural gas. Unrestricted HAPs emissions from these units is not a concern while firing ULSD. Source testing is required on three of the units to account for emission rate variability among the twelve units.

7. Donlin proposed purchasing a camp waste incinerator (EU ID 27) that meets the control and emission standards required by Table 5 of 40 C.F.R. 60 Subpart CCCC.
8. For compliance with the BACT emission limits the Department required initial source testing for larger units with add-on controls. BACT limits for EU IDs 1 through 12 require source testing on three units, instead of one, as representation for all of the units to limit emission rate variability between the twelve units. Smaller units that are not likely to exceed the BACT limits are required to either submit to the Department a manufacturer's guarantee that the units will meet the BACT limits or source test the units to show they meet the BACT requirements.
9. Construction Permit AQ0934CPT02 rescinds and replaces Construction Permit AQ0934CPT01 upon issuance, which is reflected in the title page of this permit.
10. Donlin needs to continue operating the existing EUs authorized under AQ0934ORL01 prior to commencing construction of the mine. Therefore, the Department incorporated the existing EU inventory and operational limits described in AQ0934ORL01 into Construction Permit AQ0934CPT02. However, Donlin will need to decommission/remove the existing EUs shortly after the new EUs of equivalent purpose become fully operational since they did not include the existing EUs in their ambient demonstration. The ambient air section of Construction Permit AQ0934CPT02 includes the authorization to continue operating the existing EUs during this interim period, as well as the requirement to decommission/remove the existing EUs once the replacement units become operational. The Department is taking this approach because AQ0934ORL01 ensures compliance with the Alaska Ambient Air Quality Standards (AAAQS) while allowing Donlin to avoid a minor permit.

3. PSD PERMIT REQUIREMENTS

PSD applicants must comply with the requirements of 40 C.F.R. 52.21, except as noted in 18 AAC 50.306.

40 C.F.R. 52.21(j)(1) requires that the major stationary source meet the applicable local standards, state requirements established in the Alaska State Implementation Plan (SIP), and federal standards of performance in 40 C.F.R. 60, 61, and 63. The source must meet each applicable state emissions standard as described under Section 4 of this TAR (see discussion for permit Conditions 6 – 8), the standards and associated monitoring requirements will be carried forward into the Title V operating permit for the source.

40 C.F.R. 52.21(j)(2) requires a major stationary source to apply Best Available Control Technology (BACT) for each regulated New Source Review pollutant that has the potential to emit greater than the significant amounts listed in 40 C.F.R. 52.21(b)(23)(i). Appendix B presents details of the BACT analysis for NOx, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and GHGs.

40 C.F.R. 52.21(k) through (o) requires that the source contain the requirements under each section as applicable:

40 C.F.R. 52.21(k) - *Source Impact Analysis*: This includes a review of the allowable emissions increase concerning the AAAQS and increments;

40 C.F.R. 52.21(l) – *Air Quality Models*: Use of air quality models that are consistent with

Appendix W of 40 C.F.R. 51;[2]

40 C.F.R. 52.21(m) – *Air Quality Analysis*: Measured ambient air quality data, unless exempted under 40 C.F.R. 52.21(i)(5);

40 C.F.R. 52.21(n) - *Source Information*: Include all information about the source including a description of the nature, design capacity, location, schedule for modification and layout;

40 C.F.R. 52.21(o) – *Additional Impact Analyses*: The source must review air quality impacts on the project area, such as visibility; and

40 C.F.R. 52.21(p) – *Sources Impacting Federal Class I Areas*: Review air quality impacts on the Federal Class I area.

The requirements under 40 C.F.R. 52.21(k) through (p) are addressed in the modeling report in Appendix D of this TAR.

4. PERMIT CONDITIONS

The bases for the standard and general conditions imposed in Construction Permit AQ0934CPT02 are described below.

Cover Page

18 AAC 50.544(a)(1) requires the Department to identify the stationary source, Permittee, and contact information. The Department provided this information on the cover page of the permit.

Section 1: Emissions Unit Inventory

The EUs authorized and/or restricted by this permit are listed in Table 1 of the permit. Unless otherwise noted in the permit, the information in Table 1 is for identification purposes only. Condition 1 is a general requirement to comply with AS 46.14 and 18 AAC 50 when installing a replacement EU. Condition 2 is derived from 40 C.F.R. 52.21(r)(2) and requires Donlin to commence construction of the stationary source within 18 months of permit issuance unless granted an extension in writing from the Department. Donlin would need to show that the extension is justified, in order for the Department to approve any request for an extension.

Section 2: Fee Requirements

Condition 3, Fee Requirements

18 AAC 50.306(d)(2) requires the Department to include a requirement to pay fees in accordance with 18 AAC 50.400 – 18 AAC 50.420 in each PSD permit issued under 18 AAC 50.306.

Conditions 4 and 5, Assessable Emissions

18 AAC 50.346(b)(1) requires the Department to include the Standard Permit Condition (SPC) I language for construction permits. As indicated by Condition 5.3, if the stationary source has not commenced construction or operation on or before March 31, the Permittee is

[2] The Department used the 2005 version of Appendix W for the modeling review since that is the version currently adopted by reference in 18 AAC 50.040(f). EPA promulgated an update to Appendix W on January 17, 2017, but that update does not become effective until May 22, 2017. Permitting authorities also have a one-year transition period (which ends January 17, 2018) to incorporate the update into their New Source Review programs. The Department's use and reference to the 2005 version of Appendix W for this permitting action is therefore required under State rule and allowed under Federal rule.

required to submit a transmittal letter certified by the responsible official under 18 AAC 50.205 indicating that the assessable emissions for the source are zero for the previous fiscal year with an estimate of when construction will begin.

Section 3: State Emission Standards

Condition 6 - 8, Visible Emissions (VE), PM, and Sulfur Compounds Emission Standards

40 C.F.R. 52.21(j)(1) requires the stationary source to meet each applicable limitation under the Alaska SIP. The stationary source will be subject to Title V permitting and the Title V permit, when issued, will require ongoing MR&R with the state emission standards. The Department generally requires an initial compliance demonstration for state emission standards in a Title I permit if warranted.

Ongoing MR&R for EU IDs EG-2 through SG-2 was not included in the state emission standards as these are relatively small units that will be operating for a limited amount of time, as previously described in Section 2.2.

18 AAC 50.055(a)(1): Industrial Process and Fuel-Burning VE Standards

Section 3 of the permit contains conditions that require initial compliance using 40 C.F.R. 60, Appendix A-4, Reference Method 9 and/or Appendix A-7 Reference Method 22 observation to ensure the applicable diesel-fired equipment and crushers at the facility comply with the standard. Small natural gas-fired equipment was not included as it is unlikely that these units will exceed the VE standards.

18 AAC 50.055(b)(1): Industrial Process and Fuel-Burning PM Standards

Industrial process equipment and fuel-burning equipment at the stationary source must comply with 18 AAC 50.055(b)(1), the state PM standards of 0.05 grains per dry standard cubic foot of exhaust. Initial compliance demonstrations were not included for PM as the PM emitting units are all subject to BACT limits and must demonstrate compliance with either a source test or submitting a manufacturer's guarantee. Compliance with the BACT limit will ensure compliance with the state PM standard.

18 AAC 50.055(c): Sulfur Compound Emissions Standards

Industrial process equipment and fuel-burning equipment at the stationary source must comply with 18 AAC 50.055(c), the state sulfur compounds emissions standard. Sulfur compound emissions, expressed as SO_2, from an industrial process or from fuel-burning equipment may not exceed 500 parts per million by volume (ppmv) averaged over a period of three hours. This permit does not include SO_2 initial compliance demonstrations because these units are subject to the ORL in Condition 45 requiring the use of ULSD. The use of ULSD fuel will ensure compliance with the SO_2 state emission standard.

18 AAC 50.050: Incinerator Emission Standards

Incinerators at the stationary source must comply with 18 AAC 50.050, the state incinerator emission standards which includes a VE standard and a PM standard. The Department combined the VE standards for incinerators and for industrial process and fuel-burning equipment as the standards are the same. EU IDs 27 and 28 are not subject to the incinerator PM standards because they have a rated capacity under 1,000 pounds per hour.

Section 4: Ambient Air Quality Protection Requirements

Condition 9 – 23

18 AAC 50.010 contains the ambient air quality standards (AAQS). 18 AAC 50.020 contains the maximum allowable increases (increment). The Department will include conditions to protect these standards when warranted. The Department determined that for this project, conditions are warranted to protect the AAQS and annual increment for NO_2, PM_{10}, $PM_{2.5}$, and CO as specified in Conditions 19 through 23, for the reasons described in Appendix D (Modeling Report) of this TAR.

Section 5: Best Available Control Technology

Conditions 24 – 35

The project triggers PSD review under 18 AAC 50.306 for NOx, CO, PM, PM_{10}, $PM_{2.5}$, VOCs, and GHGs. The Department performed a BACT analysis of all the available control options for equipment emitting the triggered pollutants listed above. The BACT evaluation process selects the best pollutant control option based on feasibility, economics, energy, and other impacts. The full BACT analysis is contained in Appendix B and a summary in Appendix C of this TAR.

Section 6: Owner Requested Limit to Avoid PSD Classification

Condition 36

18 AAC 50.544(h) describes the requirements for a permit classified under 18 AAC 50.508(5). This permit describes the ORL, including specific testing, monitoring, recordkeeping, and reporting requirements; it lists all equipment covered by the ORL; and describes the classification that the limit allows the applicant to avoid.

Condition 36 contains an ORL restricting the EUs at the stationary source (excluding nonroad engines) to no more than 23.2 tons of SO_2 per consecutive 12-month period to avoid PSD review under 18 AAC 50.306. This is accomplished by requiring exclusive use of ULSD as liquid fuel at the stationary source for all liquid fuel burning EUs, excluding nonroad engines. This condition includes both a ton per year limit and an operational limit.

Section 7: Owner Requested Limit to Avoid HAPs Major Classification

Conditions 37

18 AAC 50.544(h) describes the requirements for a permit classified under 18 AAC 50.508(5). This permit describes the ORL, including specific testing, monitoring, recordkeeping, and reporting requirements; it lists all equipment covered by the ORL; and describes the classification that the limit allows the applicant to avoid.

Condition 37 contains an ORL restricting the formaldehyde from EU IDs 1 through 12 to no more than 9.7 tons per 12-month rolling period to avoid being classified as a HAPs major source under 18 AAC 50.316. The Permittee is required to install an oxidation catalyst and source test to demonstrate compliance. This condition includes both a ton per year limit and an operational limit.

Section 8: General Recordkeeping and Reporting Requirements

Condition 38, Recordkeeping Requirements

The condition restates the regulatory requirements for recordkeeping, and supplements the recordkeeping defined for specific conditions in the permit. The records being kept provide an evidence of compliance with this requirement.

Condition 39, Certification

18 AAC 50.205 requires the Permittee to certify any permit application, report, affirmation, or compliance certification submitted to the Department. The Department used the language in Standard Permit Condition (SPC) XVII. This requirement is reiterated as a SPC in 18 AAC 50.345(j). The Department used the standard condition language in this construction permit.

Condition 40, Submittals

Condition 40 clarifies where the Permittee should send their reports, certifications, and other submittals required by the permit. The Department included this condition from a practical perspective rather than a regulatory obligation.

Condition 41, Information Requests

AS 46.14.020(b) allows the Department to obtain a wide variety of emissions, design and operational information from the owner and operator of a stationary source. This statutory provision is reiterated as a standard permit condition in 18 AAC 50.345(i). The Department used the standard language in this construction permit.

Condition 42, Excess Emissions and Permit Deviation Reports

This condition reiterates the notification requirements in 18 AAC 50.235(a)(2) and 18 AAC 50.240 regarding unavoidable emergencies, malfunctions, and excess emissions. Also, the Permittee is required to notify the Department when emissions or operations deviate from the requirements of the permit. The Department used the Standard Permit Condition III language.

Condition 43, Operating Reports

The Department mostly used the Standard Permit Condition VII language for the operating report condition. However, the Department modified or eliminated the Title V only aspects in order to make the language applicable for a construction permit.

Condition 44, Title V Major Source Application Submittal Date

For a stationary source that directly emits, or has the potential to emit, 100 tpy or more of any air pollutant subject to regulation, the Permittee shall file a complete application to obtain the part 70 Title V Operating Permit within 12 months after commencing operation or exceeding the 100 tpy threshold as required by 40 C.F.R. 70.5.

Condition 45, Air Pollution Prohibited

18 AAC 50.110 prohibits any emission which is injurious to human health or welfare, animal or plant life, or property, or which would unreasonably interfere with the enjoyment of life or property. Condition 55 reiterates this prohibition as a permit condition. The Department used the SPC II language for this construction permit.

Condition 46, Emission Inventory Reporting

This condition requires the Permittee to submit emissions data to the state so the state is able to satisfy the federal requirement to submit emission inventory data from point sources to the EPA as required under 40 C.F.R. 51.15 and 51.321. The emission inventory requirement applies to sources defined as point sources in 40 C.F.R. 51.50. The state must report emissions data as described in 40 C.F.R 51.15 and the data elements in Tables 2a and 2b to Appendix A of 40 C.F.R. 51 Subpart A to EPA.

The Department used the language in SPC XV, as adopted by reference under 18 AAC 50.346(b)(8), for the permit condition.

The emission inventory data is due to EPA 12 months after the end of the reporting year (40 C.F.R. 51.30(a)(1) and (b)(1)). Permittees have until April 30th to compile and submit the data to the Department. To expedite the Department's process of transferring data into EPA's electronic reporting system, the Department encourages Permittees to submit the emission inventory through the Department's electronic emission inventory submission system in the Permittee Portal on the Department's Air Online Services webpage http://dec.alaska.gov/Applications/Air/airtoolsweb/. A myAlaska account and profile are needed to gain access to the Permittee Portal. Other options are to submit the emission inventory via mail, email, or fax.

Detailed instructions on completing and submitting the emission inventory and the report form are available at the Point Source Emission Inventory page http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory by clicking the Emission Inventory Instructions button. The emission inventory instructions and report form may also be obtained by contacting the Department.

To ensure that the Department's electronic system reports complete information to the National Emissions Inventory, Title V stationary sources are required to submit with each report emissions data described in 40 C.F.R. 51.15 and the data elements in Tables 2a and 2b to Appendix A of 40 C.F.R. 51 Subpart A, as applicable. Title V stationary sources with potential annual emissions greater than or equal to any of the emission thresholds shown in Condition 56.1 for Type A (large) sources, as listed in Table 1 to Appendix A of 40 C.F.R. 51 Subpart A, are required to report emission inventory data every year for the previous calendar year (also known as the inventory year). For triennial inventory years, Type A sources only need to submit one report, not both an annual report and a separate triennial report.

Title V stationary sources with potential annual emissions greater than or equal to any of the emission thresholds for Type B (small) sources shown in Condition 56.2.a (for attainment and unclassifiable areas) and Condition 56.2.b (for nonattainment areas), as listed in Table 1 to Appendix A of 40 C.F.R. 51 Subpart A, are required to report emission inventory data every third year (i.e., triennially) for the previous inventory year. The emission thresholds for nonattainment areas listed in Condition 56.2.b vary depending on the nonattainment status of the area. As of June 9, 2017, Fairbanks and North Pole urban area have been designated by the federal administrator as "serious nonattainment" for $PM_{2.5}$. Therefore, a stationary source located in Fairbanks and North Pole urban area is subject to the triennial reporting requirement if its potential to emit is greater than or equal to any of the threshold values in Conditions 56.2.b(i), 56.2.b(ii), 56.2.b(iii) (PM_{10} only), and 56.2.b(iv).

As of the issue date of this permit, the *Donlin Gold Project* is a *"Type A"* stationary source.

Section 9: Standard Permit Conditions

Conditions 47 – 52, Standard Permit Conditions

As required under 18 AAC 50.345, the Department may include the standard permit conditions set out in subsections (c)(1) and (2), and (d) through (o), as applicable for a minor or construction permit. As required under 18 AAC 50.346, the Department will include the standard permit conditions set out in this subsection in each construction permit or Title V permit, unless the Department determines that emissions unit-specific or stationary source-specific conditions more adequately meet the requirements of this chapter, or that no comparable condition is appropriate for the stationary source or emissions unit.

The Department included all of the minor/construction permit-related standard conditions of 18 AAC 50.345 in Construction Permit AQ0934CPT02. The Department incorporated these standard conditions as follows:

- 18 AAC 50.345(c)(1) and (2) is incorporated as Condition 47 of Section 9 (Standard Permit Conditions);
- 18 AAC 50.345(d) through (h) is incorporated as Conditions 48 through 52, respectively, of Section 9 (Standard Permit Conditions);
- As previously discussed, 18 AAC 50.345(i) is incorporated as Condition 41 and 18 AAC 50.345(j) is incorporated as Condition 39 of Section 8 (Recordkeeping, Reporting, and Certification Requirements); and
- 18 AAC 50.345(k) is incorporated as Condition 53, and 18 AAC 50.345(l) through (o) are incorporated as Conditions 58 through 61, respectively, of Section 10 (General Source Testing Requirements). See the following discussion.

Section 10: General Source Test Requirements

Conditions 53 – 61

AS 46.14.180 states that monitoring requirements must be, “based on test methods, analytical procedures, and statistical conventions approved by the federal administrator or the department or otherwise generally accepted as scientifically competent.” The Department incorporated this requirement as follows:

- Condition 54 requires the Permittee to conduct their source tests under conditions that reflects the actual discharge to ambient air; and
- Condition 55 requires the Permittee to use specific EPA reference methods when conducting a source test.

Section 10 also includes the previously discussed standard conditions for source testing.

5. PERMIT ADMINISTRATION

Construction Permit AQ0934CPT02 rescinds and replaces Construction Permit AQ0934CPT01 upon issuance. The Permittee may therefore operate in accordance with Construction Permit AQ0934CPT02 upon issuance.

APPENDIX A: EMISSIONS CALCULATIONS

Table A-1 presents details of the EUs, their characteristics, and emissions. The Department obtained the emissions values from the Permittee on January 19, 2022 and made modifications to the boilers emissions based on the March 9, 2022 information request response.

Table A-1: Detailed Permanent EU Inventory and Potential to Emit (tpy)

EU ID	Hours per year[1]	Rating	CO			NOx			$PM_{2.5}$ PM_{10} EF Units	$PM_{2.5}$		PM_{10}		PM		SO_2			VOC		
			EF	Units	PTE	EF	Units	PTE		EF	PTE	EF	PTE	EF	PTE	EF	Units	PTE	EF	Units	PTE
1[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
2[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
3[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
4[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
5[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
6[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
7[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
8[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
9[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
10[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
11[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
12[2]	8,760	17,076 kW	0.18	g/kW	**29.2**	0.53	g/kW	**85.9**	g/kW	0.29	**47.0**	0.29	**47.0**	0.29	**47.0**	0.0059	g/kW	**1.0**	0.58	g/kW	**93.6**
13[3]	8,760	200 kW	4.38	g/kW	**8.4**	0.60	g/kW	**1.2**	g/kW	0.03	**0.06**	0.03	**0.1**	0.03	**0.1**	0.0066	g/kW	**0.01**	0.29	g/kW	**0.6**
14[3]	8,760	200 kW	4.38	g/kW	**8.4**	0.60	g/kW	**1.2**	g/kW	0.03	**0.06**	0.03	**0.1**	0.03	**0.1**	0.0066	g/kW	**0.01**	0.29	g/kW	**0.6**
15[4]	8,760	29.29 MMBtu/hr	0.16	lb/ MMBtu	**20.5**	0.13	lb/ MMBtu	**16.8**	lb/ MMBtu	0.012	**1.5**	0.018	**2.3**	0.025	**3.3**	0.0016	lb/ MMBtu	**0.2**	0.005	lb/ MMBtu	**0.7**
16[4]	8,760	29.29 MMBtu/hr	0.16	lb/ MMBtu	**20.5**	0.13	lb/ MMBtu	**16.8**	lb/ MMBtu	0.012	**1.5**	0.018	**2.3**	0.025	**3.3**	0.0016	lb/ MMBtu	**0.2**	0.005	lb/ MMBtu	**0.7**
17[4]	8,760	20.66 MMBtu/hr	0.16	lb/ MMBtu	**14.5**	0.13	lb/ MMBtu	**11.9**	lb/ MMBtu	0.012	**1.1**	0.018	**1.6**	0.025	**2.3**	0.0016	lb/ MMBtu	**0.1**	0.005	lb/ MMBtu	**0.5**
18[4]	8,760	16 MMBtu/hr	0.24	lb/ MMBtu	**16.8**	0.22	lb/ MMBtu	**15.6**	lb/ MMBtu	0.012	**0.83**	0.018	**1.2**	0.025	**1.8**	0.0016	lb/ MMBtu	**0.1**	0.005	lb/ MMBtu	**0.4**
19[5]	8,760	16.5 MMBtu/hr	0.082	lb/ MMBtu	**6.0**	0.15	lb/ MMBtu	**11.1**	lb/ MMBtu	0.012	**0.86**	0.018	**1.3**	0.025	**1.8**	0.0016	lb/ MMBtu	**0.1**	0.005	lb/ MMBtu	**0.4**

EU ID	Hours per year[1]	Rating	CO			NOx			$PM_{2.5}$ PM_{10} EF Units	$PM_{2.5}$		PM_{10}		PM		SO_2			VOC		
			EF	Units	PTE	EF	Units	PTE		EF	PTE	EF	PTE	EF	PTE	EF	Units	PTE	EF	Units	PTE
20[5]	8,760	16.5 MMBtu/hr	0.082	lb/ MMBtu	**6.0**	0.15	lb/ MMBtu	**11.1**	lb/ MMBtu	0.012	**0.86**	0.018	**1.3**	0.025	**1.8**	0.0016	lb/ MMBtu	**0.1**	0.005	lb/ MMBtu	**0.4**
21[6]	8,760	2 MMBtu/hr	0.082	lb/ MMBtu	**0.72**	0.098	lb/ MMBtu	**0.86**	lb/ MMBtu	0.007	**0.1**	0.007	**0.1**	0.007	**0.1**	0.0006	lb/ MMBtu	**0.01**	0.005	lb/ MMBtu	**0.047**
22[7]	8,760	2 MMBtu/hr	0.038	lb/ MMBtu	**0.34**	0.15	lb/ MMBtu	**1.35**	lb/ MMBtu	0.012	**0.10**	0.018	**0.15**	0.025	**0.22**	0.0016	lb/ MMBtu	**0.01**	0.003	lb/ MMBtu	**0.02**
23[6,8]	8,760	24.15 MMBtu/hr	0.039	lb/ MMBtu	**4.15**	0.092	lb/ MMBtu	**9.75**	lb/ MMBtu	0.007	**0.8**	0.007	**0.8**	0.007	**0.8**	0.0006	lb/ MMBtu	**0.06**	0.005	lb/ MMBtu	**0.57**
24[6,9]	8,760	95 MMBtu/hr	0.082	lb/ MMBtu	**34.3**	0.098	lb/ MMBtu	**40.8**	lb/ MMBtu	0.007	**3.1**	0.007	**3.1**	0.007	**3.1**	0.0006	lb/ MMBtu	**0.24**	0.005	lb/ MMBtu	**2.2**
25[6,10]	8,760	17.5 MMBtu/hr	0.082	lb/ MMBtu	**6.3**	0.098	lb/ MMBtu	**7.5**	lb/ MMBtu	0.007	**0.6**	0.007	**0.6**	0.007	**0.6**	0.0006	lb/ MMBtu	**0.05**	0.005	lb/ MMBtu	**0.41**
26[7,11]	8,760	17.2 MMBtu/hr	0.038	lb/ MMBtu	**2.9**	0.15	lb/ MMBtu	**11.6**	lb/ MMBtu	0.012	**0.9**	0.018	**1.3**	0.025	**1.9**	0.0016	lb/ MMBtu	**0.12**	0.003	lb/ MMBtu	**0.20**
27[12]	8,760	990 lb/hr	17	ppmvd @ 7% O_2	**0.35**	23	ppmvd @ 7% O_2	**0.78**	ppmvd @ 7% O_2	18	**0.32**	18	**0.32**	18	**0.32**	11	ppmvd @ 7% O_2	**0.52**	3.0	lb/ton	**6.50**
28[12]	8,760	0.058 ton/day	52	ppmvd @ 7% O_2	**0.01**	210	ppmvd @ 7% O_2	**0.06**	ppmvd @ 7% O_2	60	**0.01**	60	**0.01**	60	**0.01**	26	ppmvd @ 7% O_2	**0.01**	1.7	lb/ton	**0.018**
29[13]	500	600 kW	4.38	g/kW	**1.45**	7.60	g/kW	**2.51**	g/kW	0.25	**0.1**	0.25	**0.1**	0.25	**0.1**	0.0066	g/kW	**0.002**	0.40	g/kW	**0.13**
30[13]	500	600 kW	4.38	g/kW	**1.45**	7.60	g/kW	**2.51**	g/kW	0.25	**0.1**	0.25	**0.1**	0.25	**0.1**	0.0066	g/kW	**0.002**	0.40	g/kW	**0.13**
31[13]	500	1,500 kW	4.38	g/kW	**3.62**	7.60	g/kW	**6.28**	g/kW	0.25	**0.2**	0.25	**0.2**	0.25	**0.2**	0.0067	g/kW	**0.006**	0.40	g/kW	**0.33**
32[13]	500	1,500 kW	4.38	g/kW	**3.62**	7.60	g/kW	**6.28**	g/kW	0.25	**0.2**	0.25	**0.2**	0.25	**0.2**	0.0067	g/kW	**0.006**	0.40	g/kW	**0.33**
33[13]	500	1,500 kW	4.38	g/kW	**3.62**	7.60	g/kW	**6.28**	g/kW	0.25	**0.2**	0.25	**0.2**	0.25	**0.2**	0.0067	g/kW	**0.006**	0.40	g/kW	**0.33**
34[13]	500	1,500 kW	4.38	g/kW	**3.62**	7.60	g/kW	**6.28**	g/kW	0.25	**0.2**	0.25	**0.2**	0.25	**0.2**	0.0067	g/kW	**0.006**	0.40	g/kW	**0.33**
35[14]	500	252 hp	3.26	g/hp-hr	**0.45**	3.54	g/hp-hr	**0.49**	g/hp-hr	0.19	**0.03**	0.19	**0.03**	0.19	**0.03**	0.0049	g/hp-hr	**0.001**	0.19	g/hp-hr	**0.026**
36[14]	500	252 hp	3.26	g/hp-hr	**0.45**	3.54	g/hp-hr	**0.49**	g/hp-hr	0.19	**0.03**	0.19	**0.03**	0.19	**0.03**	0.0049	g/hp-hr	**0.001**	0.19	g/hp-hr	**0.026**
37[14]	500	252 hp	3.26	g/hp-hr	**0.45**	3.54	g/hp-hr	**0.49**	g/hp-hr	0.19	**0.03**	0.19	**0.03**	0.19	**0.03**	0.0049	g/hp-hr	**0.001**	0.19	g/hp-hr	**0.026**
77[15]	8,760	210 ton/hr	88	lb/hr	**385.5**	--	--	**--**	lb/hr	0.22	**1.0**	0.22	**1.0**	0.22	**1.0**	1.1	lb/hr	**4.9**	0.04	lb/hr	**0.19**
81[15]	8,760	210 ton/hr	88	lb/hr	**385.5**	--	--	**--**	lb/hr	0.22	**1.0**	0.22	**1.0**	0.22	**1.0**	1.1	lb/hr	**4.9**	0.04	lb/hr	**0.19**
85[16]	8,760	- -	--	--	**--**	--	--	**--**	lb/hr	0.40	**1.75**	0.40	**1.75**	0.40	**1.75**	--	--	**--**	--	--	**--**
86[16]	8,760	Common Stack-	--	--	**--**	--	--	**--**	--	--	**--**	--	--	--	**--**	--	--	**--**	--	--	**--**
87[16]	8,760	- --	--	--	**--**	--	--	**--**	--	--	**--**	--	--	--	**--**	--	--	**--**	--	--	**--**
88[17]	8,760	1.65 ton/hr	0.88	lb/hr	**3.8**	0.02	lb/hr	**0.1**	lb/hr	0.44	**1.9**	0.44	**1.9**	0.44	**1.9**	--	--	**--**	0.44	lb/hr	**1.9**

EU ID	Hours per year[1]	Rating	CO			NOx			$PM_{2.5}$ PM_{10} EF Units	$PM_{2.5}$		PM_{10}		PM		SO_2			VOC		
			EF	Units	PTE	EF	Units	PTE		EF	PTE	EF	PTE	EF	PTE	EF	Units	PTE	EF	Units	PTE
91-94[18]	8,760	211 gpm	--	--	**--**	--	--	**--**	lb/hr	0.19	**0.8**	0.19	**0.8**	0.19	**0.8**	--	--	**--**	--	--	**--**
97[19]	8,760	--	--	--	**--**	--	--	**--**	lb/hr	0.03	**0.1**	0.03	**0.1**	0.03	**0.1**	--	--	**--**	--	--	**--**
100[20]	8,760	--	--	--	**--**	--	--	**--**	gr/dscf	0.005	**4.2**	0.005	**4.2**	0.005	**4.2**	--	--	**--**	--	--	**--**
104[21]	8,760	3,575 lb/day	--	--	**--**	--	--	**--**	gr/dscf	0.009	**2.0**	0.009	**2.0**	0.009	**2.0**	--	--	**--**	--	--	**--**
106[21]	8,760	3,575 lb/day	--	--	**--**	--	--	**--**	gr/dscf	0.004	**4.1**	0.004	**4.1**	0.004	**4.1**	--	--	**--**	--	--	**--**
109[21]	8,760	3,575 lb/day	--	--	**--**	--	--	**--**	gr/dscf	0.009	**2.0**	0.009	**2.0**	0.009	**2.0**	--	--	**--**	--	--	**--**
111[22]	8,760	1,500 SCFM	--	--	**--**	--	--	**--**	gr/dscf	0.02	**1.13**	0.02	**1.13**	0.02	**1.13**	--	--	--	--	--	--
126[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
127[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
128[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
129[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
130[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
131[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
132[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
133[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
134[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
135[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
136[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
137[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
138[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
139[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
140[23]	7,500,000	2,500,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.10**
141[23]	19,035,000	25,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.02**
142[23]	19,035,000	25,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.02**
143[23]	1,106,184	10,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.002**

EU ID	Hours per year[1]	Rating	CO			NOx			$PM_{2.5}$ PM_{10} EF Units	$PM_{2.5}$		PM_{10}		PM		SO_2			VOC		
			EF	Units	PTE	EF	Units	PTE		EF	PTE	EF	PTE	EF	PTE	EF	Units	PTE	EF	Units	PTE
144[23]	6,776	270 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**4.5E-5**
145[23]	6,776	270 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**4.5E-5**
146[23]	3,942,411	5,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.004**
147[23]	1,390,621	5,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.002**
148[23]	1,076,771	5,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.002**
149[23]	134,596	500 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**2.0E-4**
150[23]	3,899,388	33,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.01**
151[23]	3,899,388	33,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.01**
152[23]	218,800	25,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.002**
153[23]	6,776	270 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**4.5E-5**
154[23]	55,000	9,900 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.08**
155[23]	55,000	9,900 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.08**
156[23]	10,000	5,000 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.09**
157[23]	252,695	9,900 gal	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	**0.001**
Subtotal:			*1,325.2*			*1,537.4*				*597.8*		*601.5*		*606.4*		*23.2*			*1,148.3*		
FUGITIVE EMISSIONS																					
38[24]	8,760	44,676,000 ton/yr	--	--	--	--	--	--	lb/ton	3.4E-5	**0.8**	2.3E-4	**5.0**	4.8E-4	**10.6**	--	--	--	--	--	--
39[25]	8,760	25,015 ACFM	--	--	--	--	--	--	lb/hr	2.14	**9.4**	2.14	**9.4**	2.14	**9.4**	--	--	--	--	--	--
41[25]	8,760	44,676,000 ton/yr	--	--	--	--	--	--	--	--	**--**	--	**--**	--	**--**	--	--	--	--	--	--
42[25]	8,760	44,676,000 ton/yr	--	--	--	--	--	--	--	--	**--**	--	**--**	--	**--**	--	--	--	--	--	--
43[25]	8,760	44,676,000 ton/yr	--	--	--	--	--	--	--	--	**--**	--	**--**	--	**--**	--	--	--	--	--	--
44[24]	8,760	44,676,000 ton/yr	--	--	--	--	--	--	lb/ton	3.4E-5	**0.8**	2.3E-4	**5.0**	4.8E-04	**10.6**	--	--	--	--	--	--
45[26]	8,760	5,100 ton/hr	--	--	--	--	--	--	lb/ton	3.4E-5	**0.8**	2.3E-4	**5.0**	4.8E-04	**10.6**	--	--	--	--	--	--

EU ID	Hours per year[1]	Rating	CO			NOx			$PM_{2.5}$ PM_{10} EF Units	$PM_{2.5}$		PM_{10}		PM		SO_2			VOC		
			EF	Units	PTE	EF	Units	PTE		EF	PTE	EF	PTE	EF	PTE	EF	Units	PTE	EF	Units	PTE
46[26]	8,760	5,591 ACFM	--	--	--	--	--	--	lb/hr	0.48	**2.1**	0.48	**2.1**	0.48	**2.1**	--	--	--	--	--	--
48[26]	8,760	5,591 ACFM	--	--	--	--	--	--	lb/hr	0.48	**2.1**	0.48	**2.1**	0.48	**2.1**	--	--	--	--	--	--
50[26]	8,760	5,591 ACFM	--	--	--	--	--	--	lb/hr	0.48	**2.1**	0.48	**2.1**	0.48	**2.1**	--	--	--	--	--	--
52[26]	8,760	5,591 ACFM	--	--	--	--	--	--	lb/hr	0.48	**2.1**	0.48	**2.1**	0.48	**2.1**	--	--	--	--	--	--
54[24]	8,760	3,303 ton/hr	--	--	--	--	--	--	lb/ton	3.4E-5	**0.5**	2.3E-4	**3.3**	4.8E-04	**6.9**	--	--	--	--	--	--
55-56[27]	8,760	30,017 ACFM	--	--	--	--	--	--	lb/hr	2.57	**11.3**	2.57	**11.3**	2.57	**11.3**	--	--	--	--	--	--
58[24]	8,760	660 ton/hr	--	--	--	--	--	--	lb/ton	3.4E-5	**0.1**	2.3E-4	**0.7**	4.8E-04	**1.4**	--	--	--	--	--	--
59[28]	8,760	1,500 ACFM	--	--	--	--	--	--	lb/hr	0.26	**1.1**	0.26	**1.1**	0.26	**1.1**	--	--	--	--	--	--
61[28]	8,760	1,500 ACFM	--	--	--	--	--	--	lb/hr	0.26	**1.1**	0.26	**1.1**	0.26	**1.1**	--	--	--	--	--	--
63[28]	8,760	628 ACFM	--	--	--	--	--	--	lb/hr	0.11	**0.47**	0.11	**0.47**	0.11	**0.47**	--	--	--	--	--	--
65[28]	8,760	840 ACFM	--	--	--	--	--	--	lb/hr	0.14	**0.63**	0.14	**0.63**	0.14	**0.63**	--	--	--	--	--	--
67[28]	8,760	1,324 ACFM	--	--	--	--	--	--	lb/hr	0.23	**1.0**	0.23	**1.0**	0.23	**1.0**	--	--	--	--	--	--
69[28]	8,760	3,002 ACFM	--	--	--	--	--	--	lb/hr	0.51	**2.3**	0.51	**2.3**	0.51	**2.3**	--	--	--	--	--	--
71[28]	8,760	3,002 ACFM	--	--	--	--	--	--	lb/hr	0.51	**2.3**	0.51	**2.25**	0.51	**2.3**	--	--	--	--	--	--
73[28]	8,760	2,000 ACFM	--	--	--	--	--	--	lb/hr	0.34	**1.5**	0.34	**1.50**	0.34	**1.5**	--	--	--	--	--	--
75[28]	8,760	3,002 ACFM	--	--	--	--	--	--	lb/hr	0.51	**2.3**	0.51	**2.25**	0.51	**2.25**	--	--	--	--	--	--
113[29]	--	141,512 holes/yr	--	--	--	--	--	--	lb/hole	0.04	**2.8**	0.68	**47.8**	1.3	**92.0**	--	--	--	--	--	--
114[30]	--	620 blasts/yr	6,197	lb/blast	**1921.0**	166.5	lb/blast	**51.6**	lb/blast	17.46	**5.41**	302.6	**93.8**	582.0	**180.4**	0.55	lb/blast	**0.2**	--	--	--
115[31]	8,760	13,059,932 ton/yr	--	--	--	--	--	--	lb/ton	2.3E-4	**1.5**	1.5E-3	**9.8**	3.2E-3	**20.7**	--	--	--	--	--	--
116[31]	--	5,876,969 ton/yr	--	--	--	--	--	--	lb/ton	2.3E-4	**0.7**	1.5E-3	**4.4**	3.2E-3	**9.3**	--	--	--	--	--	--
117[32]	--	0 ton/day	--	--	--	--	--	--	--	--	**--**	--	**--**	--	**--**	--	--	--	--	--	--
118[31]	8,760	7,948,468 ton/yr	--	--	--	--	--	--	lb/ton	2.3E-4	**0.9**	1.5E-3	**5.9**	3.2E-3	**12.6**	--	--	--	--	--	--
119[31]	8,760	152,286,568 ton/yr	--	--	--	--	--	--	lb/ton	2.3E-4	**17.3**	1.5E-3	**114.0**	3.2E-3	**240.9**	--	--	--	--	--	--
120[31]	8,760	155,123,914 ton/yr	--	--	--	--	--	--	lb/ton	2.3E-4	**17.6**	1.5E-3	**116.1**	3.2E-3	**245.4**	--	--	--	--	--	--

EU ID	Hours per year[1]	Rating	CO			NOx			$PM_{2.5}$ PM_{10} EF Units	$PM_{2.5}$		PM_{10}		PM		SO_2			VOC		
			EF	Units	PTE	EF	Units	PTE		EF	PTE	EF	PTE	EF	PTE	EF	Units	PTE	EF	Units	PTE
121[33]	162,861 (VMT)	VMT/yr	--	--	--	--	--	--	lb/VMT	0.022	**1.8**	0.22	**17.8**	0.90	**73.3**	--	--	--	--	--	--
122[34]	75,495	hr/yr	--	--	--	--	--	--	lb/hr	0.9	**34.1**	1.54	**58.1**	8.60	**324.5**	--	--	--	--	--	--
123[35]	45,653	hr/yr	--	--	--	--	--	--	lb/VMT	0.02	**1.3**	0.28	**18.9**	0.62	**42.7**	--	--	--	--	--	--
158[36]	101,367 (VMT)	6.7 km	--	--	--	--	--	--	lb/VMT[37]	0.0063	**0.32**	0.063	**3.2**	0.258	**13.1**	--	--	--	--	--	--
159[36]	60,173 (VMT)	10.1 km	--	--	--	--	--	--	lb/VMT[38]	0.0061	**0.18**	0.0623	**1.9**	0.251	**7.5**	--	--	--	--	--	--
160[39]	4,847,140 (VMT)	VMT/yr	--	--	--	--	--	--	lb/VMT[40]	0.0328	**79.6**	0.328	**795.6**	1.35	**3,271.0**	--	--	--	--	--	--
161[41]	Wind Erosion		--	--	--	--	--	--	--	--	**2.4**	--	**15.8**	--	**31.6**	--	--	--	--	--	--
162[36]	651,046 (VMT)	47.4 km	--	--	--	--	--	--	lb/VMT[42]	.012	**3.75**	0.12	**38.0**	0.47	**153.4**	--	--	--	--	--	--
Fugitives Subtotal:			*1,921.0*			*51.6*			*214.0*			*1,401.8*		*4,800.3*		*0.2*			*0.0*		
Total Emissions:			**3,246.2**			**1,589.0**			**811.7**			**2,003.3**		**5,406.7**		**23.4**			**1,148.3**		

Table Notes: Mining activity rates are based on the highest CO, NOx, and $PM_{2.5}$ emissions year (LOM 16), and vary per year.

1 For EU IDs 124-155 the values listed under "Hours per year" are annual throughput in gallons. For EU IDs 121-123 and 158-160 the values listed under "Hours per year" are annual vehicle miles travelled.

2 Emission factors (EFs) provided by Wärtsilä. Assumed only diesel operation to determine worst case PTE, and applied SCR and oxidation catalyst controls as required by BACT. PM, PM_{10}, and $PM_{2.5}$ emissions include filterable and condensable emissions. PTE for each engine for NOx, CO, and VOC does not include the emissions from the combined 2,190 hours of operation allowed for startup when the emissions controls are not fully operational. However, these emissions have been accounted for in total PTE for the stationary source.

3 Emission factors from 40 C.F.R. 60.4204(b), 60.4201(a), and 1039.101, Table 1. A 25% not to exceed factor of safety was applied for CO and 50% for NOx, PM, and VOC per 40 C.F.R. 60.4204(d), 60.4212(b), and 1039.101(e)(2) and (3). SO_2 emissions based on 15 ppm per ORL to use only ULSD for diesel fuel.

4 CO and NOx EFs are from applicant based on diesel firing as worst-case emissions for PTE. VOC EF taken from AP-42, Table 1.4-2 and converted from lb/MMscf. $PM_{2.5}$, PM_{10}, and PM emissions based on diesel firing as worst-case emissions for PTE using EFs from AP-42, Table 1.3-2 (condensable for No. 2 oil for all particulate sizes) combined with Table 1.3-6 (for each particulate size, total, 10, and 2.5). SO_2 emissions based on 15 ppm per ORL to use only ULSD for diesel fuel.

5 EFs are conservatively based on worst-case emissions scenarios which is burning natural gas for CO and VOC and diesel fuel for NOx, particulates, and SO_2. CO and VOC EFs taken from AP-42, Tables 1.4-1 and 1.4-2 respectively, and converted from lb/MMscf. NOx EFs taken from AP-42 Table 3.1. $PM_{2.5}$, PM_{10}, PM EFs taken from AP-42 Table 1.3-2 (condensable for No. 2 oil for all particulate sizes) combined with Table 1.3-6 (for each particulate size, total, 10, and 2.5). SO_2 emissions based on mass balance using 15 ppm per ORL to use only ULSD for diesel fuel.

6 Emission factors taken from AP-42, Table 1.4-1 for CO and NOx, and Table 1.4-2 for $PM_{2.5}$, PM_{10}, PM, VOC, and SO_2.

[7] Emission factors taken from AP-42, Table 1.3-1 for CO and NOx and Table 1.3-3 for VOC. $PM_{2.5}$, PM_{10}, PM EFs taken from AP-42 Table 1.3-2 (condensable for No. 2 oil for all particulate sizes) combined with Table 1.3-6 (for each particulate size, total, 10, and 2.5). SO_2 emissions based on 15 ppm per ORL to use only ULSD for diesel fuel.
[8] EU ID 23 includes 138 0.175 lb/MMBtu building heaters.
[9] EU ID 24 includes 19 air handling heaters.
[10] EU ID 25 includes 7 air handler heaters.
[11] EU ID 26 includes 20 portable heaters.
[12] EFs for EU IDs 27 and 28 taken from 40 C.F.R. 60 Subpart CCCC, Table 5 and Subpart LLLL, Table 2 respectively. EU ID27 . Assumed 9,570 dscf/MMBtu at 0% O_2, 0.26 Nm^3/MJ at 0% O_2, 4,500 Btu/lb waste (EU ID27), and 7,700 Btu/lb dry sludge (EU ID 28). VOC emissions for EU ID 27 from AP-42 Table 2.1-12, and conservatively uses total organic compounds from multiple chamber incinerators. Note that multiple chamber incinerators are the most representative compared to the Permittee's EU ID27, and this chapter of AP-42 (refuse combustion) did not contain an emissions factor for total nonmethane organics. VOC emissions for EU ID 28 from AP-42 Table 2.2-1 for uncontrolled total nonmethane organic compounds.
[13] Emission factors for CO, NOx, $PM_{2.5}$, PM_{10}, PM, and VOC taken from 40 C.F.R. 60.4205(b), 60.4202(a)(2), and 40 C.F.R. Part 1039 Appendix I, Table 2 (Tier 2). Although the BACT emissions limit includes NOx + VOC combined, the Department assumed 95% of NOx + NMHC emissions are attributable to NOx and 5% are attributable to VOC to not double count emissions. A 25% not to exceed factor of safety was applied per 40 C.F.R. 60.4205(e) and 60.4212(c). SO_2 emissions based on 15 ppm per ORL to use only ULSD for diesel fuel.
[14] Emission factors for CO, NOx, $PM_{2.5}$, PM_{10}, PM, and VOC taken from 40 C.F.R. 60.4205(c), Table 4. Although the BACT emissions limit includes NOx + VOC combined, the Department assumed 95% of NOx + NMHC emissions are attributable to NOx and 5% are attributable to VOC to not double count emissions. A 25% not to exceed factor of safety was applied per 40 C.F.R. 60.4205(e) and 60.4212(d). SO_2 emissions based on 15 ppm per ORL to use only ULSD for diesel fuel.
[15] CO, VOC, $PM_{2.5}$, PM_{10}, PM, and SO_2 EFs from email from T. Krumins, Hatch (10/9/2013) and Hatch Emissions Controls Summary (5/27/2014). $PM_{2.5}$, PM_{10}, PM, SO_2 and VOC EFs include 10x factor of safety.
[16] $PM_{2.5}$, PM_{10}, and PM emission factors from Hatch, Hg Emissions Controls Summary (5/27/2014).
[17] Emission factors based on Barrick Goldstrike 2006-2011 source tests data for CO, 2006-2007 source test data for NOx, 2006-2012 source test data for $PM_{2.5}$, PM_{10}, and PM, and 2006-2011 source test data for VOC.
[18] $PM_{2.5}$, PM_{10}, and PM emission factors based on Barrick Goldstrike 2008-2012 source test data.
[19] $PM_{2.5}$, PM_{10}, and PM emission factors based on Barrick Goldstirke 2008-2012 source test data.
[20] $PM_{2.5}$, PM_{10}, and PM emission factors based on Barrick Goldstrike 2004-2012 source test data.
[21] Emission factors based on Barrick Goldstrike 2008-2012 source test data.
[22] Emission factors based on vendor guarantee for dust collector (EU ID 112).
[23] VOC emissions from EPA TANKS software.
[24] Emission factors taken from AP-42, Section 13.2.4, Equation 1 where U = 1.3 mph and M= 1.8%.
[25] Emission factors based on vendor guarantee of 0.01 gr/ACF for dust collector (EU ID 40). Includes emissions from EU IDs 41-43.
[26] Emission factors based on vendor guarantee of 0.01 gr/ACF for dust collectors (EU IDs 47, 49, 51, and 53).
[27] Emission factors based on vendor guarantee of 0.01 gr/ACF for dust collector (EU ID 57).
[28] Emission factors based on vendor guarantee of 0.02 gr/ACF for dust collectors (EU IDs 60, 62, 64, 66, 68, 70, 72, 74, and 76).
[29] Emission factors taken from AP-42, Table 11.9-4.
[30] Emission factors taken from AP-42, Table 13.3-1 for CO, CSIRO for NOx, AP-42, Table 11.9-1 for $PM_{2.5}$, PM_{10}, and PM, and based on 15 ppm S in FO and maximum of 10% FO in ANFO.
[31] Emission factors taken from AP-42, Section 13.2.4, Equation 1 where U = 7.95 mph, M = 2.5%, and k taken from AP-42, Section 13.2.4.

[32] Long-term ore stockpile loading accounted for in reloading (EU ID 118). Emission factors taken from AP-42, Section 13.2.4, Equation 1 where U = 7.95 mph, M = 2.5%, and k taken from AP-42, Section 13.2.4.
[33] Emission factors taken from AP-42, Table 13.2.2, Equations 1a and 2, where s = 3.8%, W = 183 tons, P = 129, k = 0.15 ($PM_{2.5}$); 1.5 (PM_{10}); and 4.9 (PM), a = 0.9 ($PM_{2.5}$ and PM_{10}); 0.7 (PM), and b = 0.45. Assumes 90% emissions control.
[34] Emission factors taken from AP-42, Table 11.9-1, where M = 2.5% and s = 3.8%.
[35] Emission factors taken from AP-42, Table 11.9-1, where S = 3 mph.
[36] Emissions include travel from bus, light vehicle, water truck, and grader.
[37] Emission factor listed is for bus/light vehicle/water truck and taken from AP-42, Table 13.2.2, Equations 1a and 2, where s = 3.8%, W = 11.2 tons, P = 129, k = 0.15 ($PM_{2.5}$); 1.5 (PM_{10}); and 4.9 (PM), a = 0.9 ($PM_{2.5}$ and PM_{10}); 0.7 (PM), and b = 0.45. Assumes 90% emissions control. Emission factors for the grader taken from AP-42, Table 11-1, where S = 3 mph.
[38] Emission factor listed is for bus/light vehicle/water truck and taken from AP-42, Table 13.2.2, Equations 1a and 2, where s = 3.8%, W = 10.3 tons, P = 129, k = 0.15 ($PM_{2.5}$); 1.5 (PM_{10}); and 4.9 (PM), a = 0.9 ($PM_{2.5}$ and PM_{10}); 0.7 (PM), and b = 0.45. Assumes 90% emissions control. Emission factors for the grader taken from AP-42, Table 11-1, where S = 3 mph.
[39] Emissions for the Haul Road includes Ore Hauling and Waste Hauling.
[40] Emission factors taken from AP-42, Table 13.2.2, Equations 1a and 2, where s = 3.8%, W = 449.4 tons, P = 129, k = 0.15 ($PM_{2.5}$); 1.5 (PM_{10}); and 4.9 (PM), a = 0.9 ($PM_{2.5}$ and PM_{10}); 0.7 (PM), and b = 0.45. Assumes 90% emissions control
[41] See Emissions Calculations in Table A-2.
[42] Emission factor listed is for bus/light vehicle/water truck and taken from AP-42, Table 13.2.2, Equations 1a and 2, where s = 3.8%, W = 42.9 tons, P = 129, k = 0.15 ($PM_{2.5}$); 1.5 (PM_{10}); and 4.9 (PM), a = 0.9 ($PM_{2.5}$ and PM_{10}); 0.7 (PM), and b = 0.45. Assumes 90% emissions control. Emission factors for the grader taken from AP-42, Table 11-1, where S = 3 mph.

Table A-2 presents details of the EUs, their characteristics, and emissions. The Department obtained the emissions values from the Permittee on January 19, 2022. This table only includes wind erosion emissions at the stationary source.

Table A-2: Detailed Wind Erosion and Tons Emitted per Year

			$PM_{2.5}$			PM_{10}			PM		
Description	**Operation**	**Units**	**Emission Factor**	**Units**	**PTE**	**Emission Factor**	**Units**	**PTE**	**Emission Factor**	**Units**	**PTE**
Wind Erosion – Tailings[1]	798	acre			0.3			1.9			3.9
Wind Erosion - Inside Pit[1]	130.5	acre	0.006255	ton/acre-yr	0.08	0.0417	ton/acre-yr	0.5	0.0834	ton/acre-yr	1.1
Wind Erosion - Outside Pit[1]	84.2	acre	0.006255	ton/acre-yr	0.05	0.0417	ton/acre-yr	0.4	0.0834	ton/acre-yr	0.7
Wind Erosion - Camp to Mine[1]	15	acre	0.006255	ton/acre-yr	0.01	0.0417	ton/acre-yr	0.06	0.0834	ton/acre-yr	0.1
Wind Erosion - Airport to Camp[1]	22.4	acre	0.006255	ton/acre-yr	0.01	0.0417	ton/acre-yr	0.09	0.0834	ton/acre-yr	0.2
Wind Erosion - Waste Rock[1]					1.7			11.6			23.2
Wind Erosion - Short Term Stockpile[1]					0.02			0.2			0.3
Wind Erosion - Long Term Stockpile West[1]					0.03			0.2			0.4
Wind Erosion - Long Term Stockpile East[1]					0.05			0.3			0.7
Wind Erosion - Overburden					0.02			0.1			0.2
Total Emissions					**2.30**			**15.36**			**30.72**

Table Notes:
[1]Emission factors taken from AP-42, Section 13.2.5. Roads include 90% control efficiency from water and chemical spray.

Table A-3 presents details of the EUs and their GHG emissions. The Department obtained the emissions from Appendix B of the October 16, 2015 permit application.

Table A-3: Detailed GHG Emitted per Year

EU IDs	**Operation**	**Fuel[1]**	**Emission Factor Units**	**CO_2**		**CH_4**		**N_2O**		**CO_2-e[2]**
				Emission Factor[3]	**PTE (tpy)**	**Emission Factor[3]**	**PTE (tpy)**	**Emission Factor[3]**	**PTE (tpy)**	**PTE (tpy)**
1-12	15,081,772 MMBtu/yr	Diesel	kg/MMBtu	73.96	1,299,570	0.003	49.87	0.0006	9.98	1,233,790
13-14	32,893 MMBtu/yr	Diesel	kg/MMBtu	73.96	2,682	0.003	0.11	0.0006	0.02	2,691
15-16	513,172 MMBtu/yr	Diesel	kg/MMBtu	73.96	41,837	0.003	1.7	0.0006	0.34	41,981
17	181,013MMBtu/yr	Diesel	kg/MMBtu	73.96	14,757	0.003	0.6	0.0006	0.12	14,808
18	140,160 MMBtu/yr	Diesel	kg/MMBtu	73.96	11,427	0.003	0.46	0.0006	0.09	11,466
19-20	289,080 MMBtu/yr	Diesel	kg/MMBtu	73.96	23,568	0.003	0.98	0.0006	0.19	23,649
21	17,520 MMBtu/yr	Natural Gas	kg/MMBtu	53.06	1,025	0.001	0.02	0.0001	0.002	1,026
22	17,520 MMBtu/yr	Diesel	kg/MMBtu	73.96	1,428	0.003	0.06	0.0006	0.01	1,433
23	211,544 MMBtu/yr	Natural Gas	kg/MMBtu	53.06	12,374	0.001	0.23	0.0001	0.02	12,386
24	832,200 MMBtu/yr	Natural Gas	kg/MMBtu	53.06	48,674	0.001	0.92	0.0001	0.09	48,725
25	153,300 MMBtu/yr	Natural Gas	kg/MMBtu	53.06	8,966	0.001	0.17	0.0001	0.02	8,976
26	150,672 MMBtu/yr	Diesel	kg/MMBtu	73.96	12,284	0.003	0.5	0.0006	0.1	12,326
29-30	5,632 MMBtu/yr	Diesel	kg/MMBtu	73.96	459	0.003	0.19	0.0006	0.004	461
31-34	28,481 MMBtu/yr	Diesel	kg/MMBtu	73.96	2,322	0.003	0.09	0.0006	0.02	2,330
35-37	2,646 MMBtu/yr	Diesel	kg/MMBtu	73.96	216	0.003	0.01	0.0006	0.002	216
27-28	39,352 MMBtu/yr	Municipal Waste	kg/MMBtu	90.7	3,934	0.032	1.39	0.0042	0.18	4,023
77 and 81	8,760 hr/yr	N/A	ton/hr	2.15	37,659	--	--	--	--	37,659
124	8,760 hr/yr	N/A	ton/hr	9.57	83,816	--	--	--	--	83,816
125	8,760 hr/yr	N/A	ton/hr	21.6	189,359	--	--	--	--	189,359
Subtotal					*1,726,358*		*57.3*		*11.19*	*1,731,120*
FUGITIVE EMISSIONS										
114	103,236 MMBtu/yr[4]	Diesel	kg/MMBtu	73.96	11,739	0.003	0.48	0.0006	0.18	11,779
Fugitives Subtotal					*11,739*		*0.48*		*0.18*	*11,779*
Total Emissions					**1,738,097**		**57.8**		**11.4**	**1,742,900**

Table Notes:

[1]Fuel type for dual-fuel EUs was chosen to determine the worst case GHG PTE.

[2]CO_2-e is determined by combining CO_2, CH_4, and N_2O emissions using factors of 25 for CH_4 and 298 for N_2O. Factors taken from 40 C.F.R. 98, Table A-1.

[3]Emission factors based on fuel type taken from 40 C.F.R. 98, Tables C-1 and C-2.

[4]Based on 1,106,184 gal/yr and heating value of 130,167 Btu/gal

APPENDIX B: BEST AVAILABLE CONTROL TECHNOLOGY

1.0 Introduction

The Donlin Gold Project (DGP) triggered Prevention of Significant Deterioration (PSD) requirements for carbon monoxide (CO), oxides of nitrogen (NOx), particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$), volatile organic compounds (VOC), and greenhouse gases (GHG). This appendix reviews Donlin Gold, LLC.'s (Donlin's) Best Available Control Technology (BACT) analysis for CO, NOx, PM, PM_{10}, $PM_{2.5}$ (the Department will refer to PM, PM_{10}, and $PM_{2.5}$ as particulates in this BACT analysis), VOC, and GHG for its technical accuracy and adherence to accepted engineering cost estimation practices.

2.0 BACT Evaluation

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 C.F.R. 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at the Donlin Gold Project (DGP) that emit CO, NOx, particulates, VOC, and GHG, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting requirements (MR&Rs) necessary to ensure Donlin applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table 2-1 presents the EUs subject to BACT review.

Table 2-1: EUs Subject to BACT Review

EU ID	Description of EU
1 – 12	Main Power Plant
13 – 14	Small Diesel Engines
15 – 26	Boilers and Heaters
27 – 28	Camp Waste and Sewage Sludge Incinerators
29 – 37	Black Start and Emergency Diesel Engines
38, 39, 41 – 46, 48, 50, 52, 54 – 56, & 58	Ore Crushing and Transfers
59, 61, 63, 65, 67, 69, 71, 73, & 75	Mill Reagents Handling
77 & 81	Autoclaves
85 – 87	Pressure Oxidation Hot Cure
88	Carbon Regeneration Kiln
91 – 94	Electrowinning Cells
97	Mercury Retort
100	Induction Smelting Furnace
103, 104, 106, 108, and 109	Laboratories
111	Reagent Handling for Water Treatment
113 – 114	Drilling and Blasting
115 – 120	Material Loading and Unloading
124 – 125	Acidulation and Neutralization Tanks
126 – 157	Fuel Tanks
158 – 160, & 162	Unpaved Roads
161	Wind Erosion

FIVE-STEP BACT DETERMINATIONS

The following sections explain the steps used to determine BACT for CO, NOx, Particulates, VOC, and GHG for the applicable equipment.

Step 1 Identify All Potentially Available Control Options

The Department identifies all available control options for the EUs and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, CO, Particulates, VOC, and GHG emissions from equipment similar to those listed in Table 2-1.

Step 2 Eliminate Technically Infeasible Control Options:

The Department evaluates the technical feasibility of each control option based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control options deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank Remaining Control Technologies by Control Effectiveness

The Department ranks the remaining control options in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary

The Department reviews the detailed information in the permit application about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The applicant must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. An applicant proposing to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required.

Cost effectiveness for a control option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review. The Department lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed DGP's BACT analysis and made BACT determinations for NOx, CO, Particulates, VOC, and GHG for various EUs based on the information submitted by Donlin in their application, information from vendors, suppliers, sub-contractors, RBLC, and a comprehensive internet search.

3.0 Main Power Plant

Electric power for the mine will be generated from a dual-fuel fired (natural gas and ultra-low sulfur diesel [ULSD]) reciprocating-engine onsite power plant with a steam turbine utilizing waste heat recovered from the engines (combined cycle power plant). The combined cycle power plant will consist of 12 Wärtsilä Model 18V50DF engines, each rated at approximately 17 megawatts (MW), for a total of 205 MW (gross) from the engines and an additional 15 MW (gross) from the steam turbine. The total gross power output from the plant will be 220 MW.

The power plant will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide the BACT review for each of these pollutants (except SO_2) for each fuel type.

3.1 CO

Possible CO emission control technologies for large engines were obtained from the RBLC. The

RBLC was searched for all determinations in the last 10 years under the process codes 17.110 and 17.130, fuel oil and natural gas burning Large Internal Combustion Engines (>500 horsepower [hp]). The search results for gas-fired and oil-fired engines are summarized in Table 3-1 and Table 3-2, respectively.

Table 3-1. CO Control for Large Gas-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Oxidation Catalyst	11	0.08 - 0.8
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	7	4.0
No Control Specified	2	1.3 - 4.0

Table 3-2. CO Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Oxidation Catalyst	2	0.13 -3.3
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	72	0.45 - 3.7
Limited Use	5	0.5 - 2.6
No Control Specified	13	0.26 - 2.6

Step 1 – Identification of CO Control Technologies for Large Engines

From research, the Department identified the following technologies as available for CO control of engines rated at 500 hp or greater:

(a) Oxidation Catalyst

Catalytic oxidation is a flue gas control that oxidizes CO and hydrocarbon compounds to carbon dioxide and water vapor in the presence of a noble metal catalyst; no reaction reagent is necessary. The reaction is spontaneous, and no reactants are required. Catalytic oxidizers can provide oxidation efficiencies of up to 90% at temperatures between 750°F and 1,000°F; the efficiency of the oxidation temperature quickly deteriorates as the operating temperature decreases. In the Department's search of the RBLC database, the majority of large gas-fired engines used oxidation catalysts as the primary control method for CO emissions.

(b) Good Combustion Practices (GCP) and Clean Fuel

GCP typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency;
5. Proper fuel gas supply system designed to minimize effects of contaminants or fluctuations in pressure and flow on the fuel gas delivered.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCP is accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. In the Department's search of the RBLC database, the majority of large diesel-fired engines used GCP and clean fuels as the primary control method for CO emissions.

(c) Federal Emission Standards

RBLC CO determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 Subpart IIII, 40 C.F.R. 60 Subpart JJJJ, and 40 C.F.R 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Subpart JJJJ applies to stationary spark ignition internal combustion engines that were manufactured on or after July 1, 2007 for engines with a maximum engine power greater than or equal to 500 hp.

(d) Limited Operation

Limiting the operation of emissions units reduces the potential to emit of those units. However, because of the remote location of the stationary source with no access to an existing power grid, the large engines will be used for primary power generation and cannot have their hours of operation meaningfully limited. Therefore, the Department does not consider limited operation a technically feasible control technology for the large engines.

Step 2 – Elimination of Technically Infeasible CO Control Options for Large Engines

As explained in Step 1, limited operation is not a feasible technology to control CO emissions from the large engines.

Step 3 – Ranking of Remaining CO Control Options for Large Engines

The following control technologies have been identified and ranked for control of CO from the large engines:

(a)	Oxidation Catalyst	(90% Control)
(b)	Good Combustion Practices	(Less than 90% Control)
(c)	Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls

An oxidation catalyst will reduce CO emissions from EU IDs 1 through 12 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review

A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the primary CO control technologies installed on large engines.

Applicant Proposal

Donlin proposed to install an oxidation catalyst and maintain good combustion practices for each of EU IDs 1 through 12 as BACT for reducing CO emissions from natural gas and ULSD combustion. Catalytic oxidation and good combustion practices will reduce CO emissions to below the applicable CO emission limit in NSPS Subpart JJJJ for firing natural gas. The CO BACT emission rates are proposed at 0.18 g/kW-hr (0.13 g/hp-hr) when firing ULSD and 0.12 g/kW-hr (0.09 g/hp-hr) when firing natural gas in EU IDs 1 through 12. Donlin also proposed that each cold start[3] of the engines will emit 8 kilograms per start (kg/start) when firing ULSD and 10 kg/start when firing gas. For each warm start[4] Donlin proposed that the engines will emit 4 kg/start when firing ULSD and 2 kg/start when firing gas. Donlin has proposed allowance to start each diesel engine once per day. Therefore, using the conservative estimate of 30 minutes for a cold start, that equates to 2,190 combined hours of operation per 12 consecutive month period without oxidation catalysts working at full operation.

Step 5 – Selection of CO BACT for Large Engines

The Department's finding is that BACT for CO emissions from the large engines rated at more than 500 hp is as follows:

(a) CO emissions from EU IDs 1 through 12 shall be controlled by operating and maintaining an oxidation catalyst at all times the units are in operation (except for the 2,190 hours combined per year allowed for startup);

(b) CO emissions from EU IDs 1 through 12 shall not exceed 0.18 g/kw-hr when firing ULSD and 0.12 g/kw-hr when firing natural gas, averaged over a 3-hour period;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) Compliance with the proposed emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

3.2 NOx

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 and 17.130, fuel oil and natural gas burning Large Internal Combustion Engines (>500 hp) The search results for gas-fired and oil-fired engines are summarized in Table 3-3 and Table 3-4, respectively.

[3] For cold start conditions, the engine will reach steady-state conditions and the emission control system will typically reach its full abatement efficiency within 30 minutes of the start.

[4] For warm start conditions, the engine will typically reach steady-state conditions and the emission control system will reach its full abatement efficiency within 15 minutes of the start.

Table 3-3. NOx Control for Large Gas-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Selective Catalytic Reduction	3	0.084 – 0.5 (g/hp-hr) 1.45 (lb/hr)
Federal Emission Standards, Clean Fuel (including lean burn natural gas design), & Good Combustion Practices	18	0.45 – 2.0 (g/hp-hr)
No Control Specified	3	0.5 – 2.0 (g/hp-hr)

Table 3-4. NOx Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	1	0.4
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	70	0.3 - 19
Fuel Injection Timing Retard	6	4.5 - 9.6
Limited Use	2	3.3 - 4.8
No Control Specified	9	2.8 - 5.3

Step 1 – Identification of NOx Control Technologies for Large Engines

From research, the Department identified the following technologies as available for NOx control of engines rated at 500 hp or greater:

(a) Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the engine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent.

(b) Lean-Burn Combustion Technology (Natural Gas)

Natural gas and air are combined before being introduced into the cylinders. The low fuel/air ratio (lean-burn) reduces NOx emissions due to a lower combustion temperature.

(c) Federal Emission Standards

See control description in Section 3.1. The Department considers meeting the technology based New Source Performance Standards as a technically feasible control technology for the large engines.

(d) Ignition Timing Retard (ITR)

ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, an increase in particulate matter emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in the particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Limited Use
See control description in Section 3.1. As previously stated, the limited use is not a feasible control for the large engines that will need to continuously operate to provide power for the stationary source.

(f) Good Combustion Practices (GCPs)
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible NOx Control Options for Large Engines
As explained in Step 1, the Department does not consider ignition timing retard or limited use as technically feasible control technologies for the large engines.

Step 3 – Ranking of Remaining NOx Control Options for Large Engines
The following control technologies have been identified and ranked for control of NOx from the large engines:

(a) SCR (80% - 90% Control)

(b) GCPs and Lean Burn (Less than 80% Control)

(c) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for engines of this size. Environmental impacts are that the SCR adds exhaust back pressure that decreases the engine's efficiency and requires additional fuel consumption; the SCR catalyst does need to be replaced and recycled as necessary, and the SCR will emit ammonia from the ammonia slip of the system. The ammonia slip for the large diesel engines are limited to no greater than 10 ppmv.

RBLC Review
A review of similar units in the RBLC indicates that SCR and good combustion practices are the primary NOx control technologies installed on large engines.

Applicant Proposal
Donlin proposed to install SCR and use good combustion practices for EU IDs 1 through 12 as BACT for reducing NOx emissions from combustion of natural gas and ULSD. Using SCR and good combustion practices will reduce NOx emissions to below the applicable NOx emission limit in NSPS Subpart JJJJ for firing natural gas and Subpart IIII for firing ULSD. The NOx BACT emission rates will be 0.08 g/kW-hr (0.06 g/hp-hr) when firing natural gas and 0.53 g/kW-hr (0.40 g/hp-hr) when firing ULSD in EU IDs 1 through 12. Donlin also proposed that each cold start[3] of the engines will emit 70 kilograms per start (kg/start) when firing ULSD and 10 kg/start when firing gas. For each warm start[4] Donlin proposed that the engines will emit 30 kg/start when firing ULSD and 5 kg/start when firing gas. Donlin has proposed allowance to start each diesel engine once per day. Therefore, using the conservative estimate of 30 minutes for a cold start, that equates to 2,190 combined hours of operation per 12 consecutive month period without SCR working at full operation.

Step 5 – Selection of NOx BACT for Large Engines
The Department's finding is that BACT for NOx emissions from the large engines rated at more than 500 hp is as follows:

(a) NOx emissions from EU IDs 1 through 12 shall be controlled by operating and maintaining selective catalytic reduction at all times the units are in operation (except for the 2,190 hours combined per year allowed for startup);

(b) NOx emissions from EU IDs 1 through 12 shall not exceed 0.53 g/kw-hr when firing ULSD and 0.08 g/kw-hr when firing natural gas, averaged over a 3-hour period;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) Compliance with the proposed emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

3.3 Particulates

Possible particulate emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 and 17.130, fuel oil and natural gas burning Large Internal Combustion Engines (>500 hp). The search results for gas-fired and oil-fired engines are summarized in Table 3-5 and Table 3-6, respectively.

Table 3-5. Particulate Control for Large Gas-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Clean Fuel, Good Combustion Practices, & No Control Specified	27	0.0001 – 0.15 (g/hp-hr) 0.0001 – 0.01 (lb/MMBtu)

Table 3-6. Particulate Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Diesel Particulate Filter	3[1]	0.52 – 0.54 (lb/hr) 0.15 (g/hp-hr)
Clean Fuel, Good Combustion Practices, Limited Operation & Federal Emissions Standards	84	0.022 – 0.4 (g/hp-hr)
No Control Specified	26	0.025 – 0.2 (g/hp-hr)

Table Notes
1. Although the number of determinations appears to show three different sources, this is actually three determinations for different particulate types from the same source (MI-0433), which includes two 1,000 kW emergency engines.

Step 1 – Identification of Particulate Control Technologies for Large Engines

From research, the Department identified the following technologies as available for particulates control of engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. The Permittee contacted Wartsila and was informed that there are no DPFs available for large, medium speed engines such as the units proposed for the Donlin Gold project. Therefore, the Department considers DPF a technically infeasible control technology for the large engines.

(b) Good Combustion Practices and Clean Fuel
See control description in Section 3.1. The Department considers GCPs and clean fuel a technically feasible particulate control for the large engines.

(c) Federal Emission Standards
See control description in Section 3.1. The Department considers meeting the technology based New Source Performance Standards as a technically feasible control technology for the large engines.

(d) Limited Use
See control description in Section 3.1. As previously stated, the limited use is not a feasible control for the large engines that will need to continuously operate to provide power for the stationary source.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Large Engines
As explained in Step 1, the Department does not consider limited use or DPFs as technically feasible control technologies for the large engines.

Step 3 – Ranking of Remaining Particulate Control Options for Large Engines
Donlin has accepted the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Good combustion practices, clean fuel, and federal emissions standards will reduce particulate emissions from EU IDs 1 through 12 while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices, clean fuels, and federal emissions standards are the primary particulate control technologies installed on large engines. The only large engines with DPF are 1,000 kW, which is significantly smaller than the 17,000 kW Wartsila engines that are not compatible with DFP controls.

Applicant Proposal
Donlin proposed to use clean fuel and good combustion practices for EU IDs 1 through 12 as BACT for reducing particulate emissions from combustion of natural gas and ULSD. Natural gas is the cleanest fossil fuel and Donlin has proposed to use fuel oil No. 1 that meets ULSD standards as it has a negligible fuel ash content. Using these particulate control methods will reduce particulate emissions to below the applicable particulate emission limit in NSPS Subpart IIII for firing ULSD. Particulate BACT emission rates will be 0.13 g/kW-hr (0.10 g/hp-hr) when firing natural gas and 0.29 g/kW-hr (0.22 g/hp-hr, including condensable) when firing ULSD in EU IDs 1 - 12. Donlin also proposed that each cold start[3] of the engines will emit 3.5 kilograms per start (kg/start) when firing ULSD and 1.5 kg/start when firing gas. For each warm start[4] Donlin proposed that the engines will emit 3.5 kg/start when firing ULSD and 1.2 kg/start when firing gas.

Step 5 – Selection of Particulate BACT for Large Engines
The Department's finding is that BACT for particulate emissions from the large engines rated at more than 500 hp is as follows:

(a) Particulate emissions from EU IDs 1 through 12 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) Particulate emissions from EU IDs 1 through 12 shall not exceed 0.29 g/kw-hr[5] when firing ULSD and 0.13 g/kw-hr when firing natural gas, averaged over a 3-hour period; and

[5] Note that the particulate BACT emission limit is for total particulate emissions (filterable and condensable). Particulate emission limits in NSPS Subpart IIII for EUs 1 through 12 only include front-half (filterable) emissions, as measured by EPA Reference Method 5 (NSPS Subpart IIII, Table 7).

(c) Compliance with the proposed emission limit will be demonstrated by providing a manufacturer's emission guarantee and conducting a performance test to obtain an emission rate.

3.4 VOC

Possible VOC emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 and 17.130, fuel oil and natural gas burning Large Internal Combustion Engines (>500 hp). The search results for gas-fired and oil-fired engines are summarized in Table 3-7 and Table 3-8, respectively.

Table 3-7. VOC Control for Large Gas-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Oxidation Catalyst	16	0.091 – 0.7 g/hp-hr 26 ppmv @ 15% O_2
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	5	1.0 g/hp-hr
No Control Specified	1	1 g/hp-hr

Table 3-8. VOC Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Oxidation Catalyst	2	0.16 – 0.18
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	47	0.015 – 4.8
Limited Operation	2	0.09 – 0.5
No Control Specified	5	0.15 – 0.59

Step 1 – Identification of VOC Control Technologies for Large Engines

From research, the Department identified the following technologies as available for VOC control of engines rated at 500 hp or greater:

(a) Oxidation Catalyst
See control description in Section 3.1.

(b) Good Combustion Practices and Clean Fuel
See control description in Section 3.1.

(c) Federal Emission Standards
See control description in Section 3.1. The Department considers meeting the technology based New Source Performance Standards as a technically feasible control technology for the large engines.

(d) Limited Use
See control description in Section 3.1. As previously stated, the limited use is not a feasible control for the large engines that will need to continuously operate to provide power for the stationary source.

Step 2 – Elimination of Technically Infeasible VOC Control Options for Large Engines

As explained in Step 1, limited operation is not a feasible technology to control VOC emissions from the large engines.

Step 3 – Ranking of Remaining VOC Control Options for Large Engines

The following control technologies have been identified and ranked for control of VOC from the large engines:

(a) Oxidation Catalyst (90% Control)

(b) GCPs and Clean Fuel (Less than 90% Control)

(c) Federal Emissions Standards (Baseline)

Step 4 – Evaluate the Most Effective VOC Controls

An oxidation catalyst will reduce VOC emissions from EU IDs 1 through 12 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review

A review of similar units in the RBLC indicates that an oxidation catalyst and good combustion practices are the primary VOC control technologies installed on large engines.

Applicant Proposal

Donlin proposed to install an oxidation catalyst and good combustion practices for EU IDs 1 through 12 as BACT for reducing particulate emissions from combustion of natural gas and ULSD. Using an oxidation catalyst and good combustion practices will reduce VOC emissions to below the applicable VOC emission limit in NSPS Subpart JJJJ for firing natural gas. VOC BACT emission rates will be 0.09 g/kW-hr (0.07 g/hp-hr) when firing natural gas and 0.21 g/kW-hr (0.16 g/hp-hr) when firing ULSD in EU IDs 1 through 12. Donlin also proposed that each cold start[3] of the engines will emit 6 kilograms per start (kg/start) when firing ULSD and 7 kg/start when firing gas. For each warm start[4] Donlin proposed that the engines will emit 4 kg/start when firing ULSD and 2.5 kg/start when firing gas. Donlin has proposed allowance to start each diesel engine once per day. Therefore, using the conservative estimate of 30 minutes for a cold start, that equates to 2,190 combined hours of operation per 12 consecutive month period without oxidation catalysts working at full operation.

Step 5 – Selection of VOC BACT for Large Engines

The Department's finding is that BACT for VOC emissions from the large engines rated at more than 500 hp is as follows:

(a) VOC emissions from EU IDs 1 through 12 shall be controlled by operating and maintaining an oxidation catalyst at all times the units are in operation (except for the 2,190 hours combined per year allowed for startup);

(b) VOC emissions from EU IDs 1 through 12 shall not exceed 0.21 g/kw-hr when firing ULSD and 0.09 g/kw-hr when firing natural gas, averaged over a 3-hour period;

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(d) Compliance with the proposed emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

3.5 GHG

Possible GHG emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 and 17.130, fuel oil and natural gas burning Large Internal Combustion Engines (>500 hp). The search results for gas-fired and oil-fired engines are summarized in Table 3-9.

Table 3-9. GHG Control for Large Gas-Fired and Oil-Fired Engines

Control Technology	Gas-Fired Emission Limits (tons per year)	Oil-Fired Emission Limits (tons per year)
Good Combustion Practices & Clean Fuel	58 – 48,724	37 – 1,299,630
No Control Specified	23 – 78,490	14 – 7,194

Step 1 – Identification of GHG Control Technologies for Large Engines

From research, the Department identified the following technologies as available for GHG control of engines rated at 500 hp or greater:

(a) Carbon Capture and Sequestration (CCS)

The EPA Guidance classifies CCS as "an add-on pollution control technology that is 'available' for facilities emitting CO_2 in large amounts." Donlin has included a description of CCS, and a review of the technology in their permit application.

CCS is a broad term that includes a number of technologies that involves three general steps: 1) capturing the carbon dioxide directly at its source and compressing it, 2) transporting, and 3) storing it in non-atmospheric reservoirs. Capture, the most energy-intensive of all the processes, can be done either through pre-combustion methods or post-combustion methods. Pre-combustion requires the use of oxygen instead of air to combust the fuel. In general, pre-combustion reduces the energy required and the cost to remove CO_2 emissions from the combustion process. The concentration of CO_2 in the untreated gas stream is higher in pre-combustion capture, thereby requiring less and cheaper equipment. The other method is post-combustion, applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases.

After capture, the CO_2 is compressed to a near-liquid state and transported via pipeline to a designated storage area. These reservoirs are deep enough for the pressure of the earth to keep it in a liquidized form where it will be sequestered for thousands of years. Depleted oil and gas reservoirs are the most practical places for storing CO_2 emissions that would otherwise be emitted back into the atmosphere. Other options for storage include deep saline formations, un-mineable coal seams, and even offshore storage. The stored CO_2 is expected to remain underground for as long as thousands, even millions of years.

The Department's research did not identify CCS as a control technology used to control GHG emissions from large engines or any other emission unit type installed at any facility in the RBLC database. Additional research outside of the RBLC documented no operational CCS operations in the US at any mining facilities. The EPA's 1990 Draft NSR Workshop Manual states, "Innovative controls that have not been demonstrated on any source type similar to the proposed source need not be considered in the BACT analysis." Additionally, the Donlin Gold Project is a very remote stationary source in Western Alaska's interior that is not connected to a road system or year-round port. In addition, the location of the stationary source does not contain the appropriate underground geologic formations for sequestering carbon.[6] Additionally, the Department

[6] Alaska Geologic Carbon Sequestration Potential Estimate: Screening Saline Basins and Refining Coal Estimates. Available at the following website :https://dog.dnr.alaska.gov/Home/Search?q=Alaska+Geologic+Carbon+Sequestration+Potentia

contacted the Alaska Department of Natural Resources (DNR) who stated that, as of July 1, 2022, "At this time, the state does not have the regulatory framework to permit the leasing of its lands for CCS projects." Thus there is no viable CCS facility within reasonable proximity for internment of CO_2 sequestration. Therefore, the Department does not consider CCS to be a technically feasible control option for controlling GHG emissions from the stationary source.

(b) Engine with Waste Heat Recovery (Combined Cycle or Combined Heat and Power)
In a combined cycle power plant, waste heat recovery units are added to the exhausts of the engines and recover previously unused energy to drive a steam turbine generator (STG). In a Combined Heat and Power (also known as cogeneration) power plant, waste heat from the engine exhaust is put to a productive use such as heating a building or used for a process that requires heat inputs. Utilizing waste heat in engines leads to a more energy efficient operation because the additional power produced by the STG and heat produced by the engine does not require additional fuel consumption. Besides the STG, this configuration requires additional equipment such as condensers, deaerator, and boiler feed pump, which increases the footprint and the cost of the facility. The Permittee has proposed a combined cycle power plant with waste heat recovery and the Department considers this a feasible control technology for the large engines.

(c) GCPs and Clean Fuels
See control description in Section 3.1. GHG emissions in the exhaust of liquid or gas-fired engines are directly related to the carbon content in the fuel. Natural gas has the lowest amount of GHG emissions per Btu of energy of any fossil fuel and is considered a feasible control technology for the large engines.

Step 2 – Elimination of Technically Infeasible GHG Control Options for Large Engines
CCS is technically infeasible for the reasons stated in Step 1.

Step 3 – Ranking of Remaining GHG Control Options for Large Engines
Donlin has accepted the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Good combustion practices, clean fuels, and operating a combined cycle power plant will reduce GHG emissions from EU IDs 1 through 12 while having minimal energy and environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and clean fuel are the principal GHG control technologies used to minimize emissions on large engines.

Applicant Proposal
Donlin proposed to install new energy efficient Wärtsilä Model 18V50DF engines operated in combined cycle and good combustion practices for EU IDs 1 through 12 as BACT for reducing GHG emissions from combustion of natural gas and ULSD. Waste heat from the engines will be recovered to enhance power output efficiency. The heat rate of the combined cycle plant will be 8,283 Btu/kW-hr (HHV) for natural gas firing and 8,547 Btu/kW-hr (HHV) for ULSD firing. GHG BACT maximum emissions will be 870,501 tpy when firing natural gas and 1,233,790 tpy when firing ULSD in EU IDs 1 through 12.

Step 5 – Selection of GHG BACT for Large Engines
The Department's finding is that BACT for GHG emissions from the large engines rated at more than 500 hp is as follows:

(a) GHG emissions from EU IDs 1 through 12 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation; and

(b) GHG emissions from EU IDs 1 through 12 shall not exceed 1,233,790 tpy combined when firing ULSD and 870,501 tpy combined when firing natural gas.

4.0 Ore Crushing and Transfers

The DGP ore crushing circuit includes ore gyratory crushing, coarse ore transfers, and recycle pebble crushing. Mined ore will be loaded through a dump pocket with a rock breaker (EU ID 38) to the gyratory crusher (EU ID 41). The gyratory crusher discharges through a surge pocket (EU 42) and apron feeder (EU ID 43). Additional EUs associated with this system are the gyratory crusher circuit (EU ID 39) and gyratory crusher discharge conveyor (EU ID 44).

Ore will then be moved by conveyor (EU ID 45) to the coarse ore stockpile. Four apron feeders (EU IDs 46, 48, 50, 52) will reclaim and transfer the coarse ore stockpile to the semi-autogenous grinding (SAG) mill feed conveyor (EU ID 54).

The SAG mill is a wet process that does not produce particulate emissions and is not included in the BACT analysis for this reason. Material discharge from the SAG mill will be washed and screened, and the oversize material will be transferred to the pebble crushers (EU IDs 55 and 56). After crushing, the ore will be discharged to the pebble discharge conveyor (EU ID 58) which transfers material to the SAG mill feed conveyor.

The ore crushers and conveyors will only emit particulates. The following section provides the BACT review for particulates.

4.1 Particulates

Possible particulate emission control technologies for crushers and conveyors were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process name description containing the keywords “crush” or “conveyor”. The search results for crushers and conveyors are summarized in Table 4-1 and Table 4-2, respectively.

Table 4-1. Particulate Control for Crushers

Control Technology	Number of Determinations	Emission Limits (gr/dscf)
Dust Collector/Fabric Filter/Baghouse	19	0.002 - 0.009
Enclosure	2	0.002
Water Sprays	3	No control specified

Table 4-2. Particulate Control for Conveyors

Control Technology	Number of Determinations	Emission Limits
Dust Collector/Fabric Filter/Baghouse	17	0.0015 - 0.003 gr/dscf 0.19 – 2.3 lb/hr
Enclosure	6	0.0015 – 0.003 gr/dscf 0.02 – 0.85 lb/hr
Wet scrubbers	3	0.0079 gr/dscf 0.43 – 0.47 lb/hr

Step 1 – Identification of Particulate Control Technologies for Crushers and Conveyors

From research, the Department identified the following technologies as available for particulate control of crushers and conveyors:

(a) Dust Collectors

Dust collectors or baghouses are comprised of an array of filter bags contained in housing. Air passes through the filter media from the "dirty" to the "clean" side of the bag. These devices undergo periodic bag cleaning based on the build-up of filtered material on the bag as measured by pressure drop across the device. The cleaning cycle is set to allow operation within a range of design pressure drop. Fabric filters are characterized by the type of cleaning cycle - mechanical-shaker, pulse-jet, and reverse-air. According to the EPA's Air Pollution Control Cost Manual[7], "Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9 percent."

(b) Water Sprays
Water sprays are used to wet the material to minimize the amount of fugitive dust.

(c) High Moisture Material
Material with a higher moisture content will produce less particulate emissions when transported via conveyor or sent through a crusher.

(d) Enclosure
Enclosure structures shelter material from wind entrainment and are used to control particulate emissions. Enclosures can either fully or partially enclose the source and control efficiency is dependent on the level of enclosure.

(e) Wet Scrubber
Wet Scrubbers use a scrubbing solution to remove particulate matter from exhaust streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid flows in the opposite direction as the gas flow.

(f) Electrostatic Precipitator (ESP)
ESPs remove particulates from a gas stream by electrically charging particles with a discharge electrode in the gas path and then collecting the charged particles on the grounded.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Crushers and Conveyors
Due to design of the conveyors, it is infeasible to install dust collectors or ESPs to control particulates on these devices.

Step 3 – Ranking of Remaining Particulate Control Options for Crushers and Conveyors
The following control technologies have been identified and ranked for control of particulates from the crushers and conveyors:

(a) Dust Collectors	(>99% Control)
(b) Enclosure	(>99% Control)
(c) Wet Scrubber	(>97%)
(d) Water Sprays	(up to 90% Control)
(e) High Moisture Material	(less than 90% Control)

[7] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Step 4 – Evaluate the Most Effective Controls

For the gyratory crusher, dump pocket, and conveyors where a dust collector is infeasible (EU IDs 38, 44, 45, 54, and 58) an enclosure is the most effective method of control for particulates. For the gyratory crusher circuit, crusher, surge pocket, and apron feeders (EU IDs 39, 41 – 43, 46, 48, 50, 52, 55, and 56) dust collectors are the most effective control method.

RBLC Review

A review of similar units in the RBLC indicates that dust collectors and enclosures are the primary particulate control technologies installed on crushers and conveyors. A cost analysis was not necessary as Donlin chose to use the most effective of the technically feasible control devices for the crushers and conveyors.

Applicant Proposal

Donlin proposed to use dust collectors for EU IDs 39, 41 - 43, 46, 48, 50, 52, 55, and 56 as BACT for reducing particulate emissions. Donlin proposed to use enclosures for EU IDs 38, 44, 45, 54, and 58 as BACT for reducing particulate emissions on the conveyors. The particulate BACT emission rates for the units with dust collectors will be 0.01 gr/dscf which is below the applicable NSPS Subpart LL limit. The particulate BACT emission rates for the units with enclosures will be 0.00048 lb/ton and will be able to achieve the required no more than 10 percent opacity requirement for fugitive emissions under NSPS Subpart LL.

Step 5 – Selection of Particulate BACT for Ore Crushing and Transfers

The Department's finding is that BACT for particulate emissions for ore crushing and transfers is as follows:

(a) Particulate emissions from EU IDs 39, 41 - 43, 46, 48, 50, 52, 55, and 56 shall be controlled by operating dust collectors at all times the units are in operation;

(b) Particulate emissions from EU IDs 39, 41 - 43, 46, 48, 50, 52, 55, and 56 shall not exceed 0.01 gr/dscf averaged over a 3-hour period;

(c) Particulate emissions from EU IDs 38, 44, 45, 54, and 58 shall be controlled by operating the EUs in an enclosure at all times the units are in operation;

(d) Particulate emissions from EU IDs 38, 44, 45, 54, and 58 shall not exceed 0.00048 lb/ton of material processed averaged over a 3-hour period; and

(e) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

5.0 Autoclaves

The autoclave circuit includes two autoclaves (EU IDs 77 and 81) operating in parallel. The autoclaves will be used for the oxidation of gold-bearing sulfide minerals to metal sulfates using a combination of heat, acid, and oxygen sparging. The autoclaves will emit CO, particulates, VOC, SO_2, H_2S, and GHG. The following sections provide a BACT review for each of these pollutants (except SO_2 and H_2S).

Other than the determinations for DGP's original construction permit, the RBLC currently does not have determinations for autoclaves with the same function. The only autoclave entry is for an autoclave used for pitch impregnation.

5.1 CO

Possible CO emission control technologies for autoclaves were determined based on research for similar ore autoclaves. Nevada currently has two gold mines using similar units for a total of 8 autoclaves, none of which use controls for CO emissions.

Step 1 – Identification of CO Control Technologies for Autoclaves

From research, the Department identified the following technologies as available for CO control of autoclaves:

(a) Thermal Oxidation

The thermal oxidizer has a stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the gas containing CO is heated from its inlet temperature to its ignition temperature (the temperature at which the combustion reaction rate (and consequently the energy production rate) exceeds the rate of heat losses, thereby raising the temperature of the gases to some higher value). Thus, any CO/air mixture will ignite if its temperature is raised to a sufficiently high level. The CO-containing mixture ignites at some temperature between the preheat temperature and the reaction temperature. The ignition occurs at some point during the heating of a waste stream. The mixture continues to react as it flows through the combustion chamber.

Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 °F to 2,000 °F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the level of control. Regenerative thermal oxidizers consist of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it to the combustion chamber outlet temperature. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the auxiliary fuel savings to make such a system economical.

The Department's research only identified one instance of autoclaves in the RBLC at a pitch impregnation source (RBLC Source SC-0142). The Department notes that this source is listed as employing a thermal oxidizer only for VOC controls. There are no other BACT determinations and no other installations of thermal oxidizers on ore processing autoclaves. Due to a lack of information concerning the use of thermal oxidizers as a control device for autoclaves, the Department does not consider thermal oxidizers to be a technically feasible control option for controlling CO emissions from the autoclaves.

(b) Catalytic Oxidation

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors; nevertheless it is considered a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures (compared to thermal oxidation) without the catalyst undergoing change itself. Catalytic oxidizers operate at 650°F to 1000°F and require approximately 1.5 to 2.0 ft^3 of catalyst per 1,000 standard ft^3 gas flow.

Emissions from some emission units may contain significant amount of particulates. These particulates can poison the catalyst resulting in the failure of catalytic oxidation. For some fuels, such as coal and residual oil, contaminants would likely be present in such concentrations so as to foul catalysts quickly thereby making such systems infeasible due to the need to constantly replace catalyst materials. In addition, the use of oxidation catalysts on units with high sulfur fuels can also result in the creation of sulfuric acid mist through the conversion of SO_2 to SO_3 and subsequent combination with moisture in the exhaust gas.

The Department's research did not identify catalytic oxidation as a control technology used to control CO emissions from autoclaves installed at any facility in the RBLC database. The EPA's 1990 Draft NSR Workshop Manual states, "Innovative controls that have not been demonstrated on any source type similar to the proposed source need not be considered in the BACT analysis." This control technology has not been demonstrated in a commercial application for ore processing autoclaves. Therefore, for the purpose of this BACT analysis, the Department does not consider catalytic oxidation to be a technically feasible control option for controlling CO emissions from the autoclaves.

(c) Good Operating Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible CO Control Options for Autoclaves
Thermal and catalytic oxidation controls are considered technically infeasible for the reasons stated in Step 1.

Step 3 – Ranking of Remaining CO Control Options for Autoclaves
Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Good operating practices will reduce CO emissions from EU IDs 77 and 81 while having minimal energy and environmental impacts.

Applicant Proposal
Donlin proposed to use good operating practices for controlling CO emissions from the autoclaves. The CO BACT emission rate will be 88.0 lb/hr for EU IDs 77 and 81.

Step 5 – Selection of CO BACT for Autoclaves
The Department's finding is that BACT for CO emissions for autoclaves is as follows:

(a) CO emissions from EU IDs 77 and 81 shall be controlled by maintaining good operating practices at all times the units are in operation;

(b) CO emissions from EU IDs 77 and 81 shall not exceed 88 lb/hr each averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

5.2 Particulates

Possible particulate emission control technologies for autoclaves were determined based on research for similar ore autoclaves. Nevada currently has two gold mines using similar units with a total of 8 autoclaves. The search results for ore autoclaves are summarized in Table 5-1.

Table 5-1. Particulate Control for Autoclaves

Control Technology	Number of Determinations	Emission Limits (lb/hr)
Venturi Scrubber	5	2.28 – 8.4
Primary and Secondary Venturi Scrubber	3	2 (3 EU combined limit)

Step 1 – Identification of Particulate Control Technologies for Autoclaves
From research, the Department identified the following technologies as available for particulate control of ore autoclaves:

(a) **Venturi Scrubber**
Venturi scrubbers are a variety of wet scrubbers that removes air pollutants, primarily particulates, by inertial and diffusional interception.

(b) **Wet Scrubber**
See control description in Section 4.1.

(c) **Dust Collector**
See control description in Section 4.1.

(d) **ESP**
See control description in Section 4.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Autoclaves
The feasibility of using a dust collector or wet ESP for controlling particulates from an autoclave is unknown as they are not currently in use. It is unlikely that a wet ESP would be more effective than a venturi scrubber, and because of the high moisture content in the autoclave exhaust, plugging of dust collectors is possible.

Step 3 – Ranking of Remaining Particulate Control Options for Autoclaves
The following control technologies have been identified and ranked for control of particulates from the autoclaves.

(a) Venturi Scrubber (70%-99% Control)

(b) Wet Scrubber (50%-99% Control)

Step 4 – Evaluate the Most Effective Controls
A venturi scrubber for each of the autoclaves would be the most effective particulate control.

Applicant Proposal
Donlin proposed to use a venturi scrubber on each autoclave stack to reduce particulate emissions from EU IDs 77 and 81. The particulate BACT emission rates will be 0.22 lb/hr for EU IDs 77 and 81.

Step 5 – Selection of Particulate BACT for Autoclaves
The Department's finding is that BACT for particulate emissions for autoclaves is as follows:

(a) Particulate emissions from EU IDs 77 and 81 shall be controlled by operating and maintaining venturi scrubbers at all times the units are in operation;

(b) Particulate emissions from EU IDs 77 and 81 shall not exceed 0.22 lb/hr each averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

5.3 VOC

Possible VOC emission control technologies for autoclaves were determined based on research for similar ore autoclaves. Nevada currently has two gold mines using similar units with a total of 8 autoclaves.

Step 1 – Identification of VOC Control Technologies for Autoclaves

From research, the Department identified the following technologies as available for VOC control of autoclaves:

(a) Thermal Oxidation

See control description in Section 5.1. As previously mentioned, the Department notes that one source (RBLC Source SC-0142) is listed as employing a thermal oxidizer as a VOC control for autoclaves for pitch impregnation. As previously mentioned, the Department does not consider thermal oxidation to be a technically feasible control option. This control technology has not been demonstrated in a commercial application for ore processing autoclaves

(b) Catalytic Oxidation

See control description in Section 5.1. As previously mentioned, the Department does not consider catalytic oxidation to be a technically feasible control option. This control technology has not been demonstrated in a commercial application for ore processing autoclaves.

(c) Good Operating Practices

See control description in Section 3.1.

(d) Activated Carbon Adsorbers

Adsorption is a surface phenomenon in which VOCs are selectively adsorbed on the surface of activated carbon. Physical adsorption is the result of the intermolecular forces of attraction between molecules of the solid and of the substance adsorbed. For example, when the intermolecular attractive forces between a solid and gas are greater than those existing between the molecules of the gas itself, the gas will condense on the surface of the solid. Activated carbon is effective in adsorbing organic compounds from a humid gas stream because it does not show a higher affinity for the polar water molecules, due to the neutral carbon atoms with no electrical gradients between molecules.

Step 2 – Elimination of Technically Infeasible VOC Control Options for Autoclaves

Thermal and catalytic oxidation controls are considered technically infeasible for the reasons stated in Step 1.

Step 3 – Ranking of Remaining VOC Control Options for Autoclaves

Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

Carbon adsorption is the best VOC control technology for EU IDs 77 and 81.

Applicant Proposal

Donlin proposed to use carbon adsorption for controlling VOC emissions from the autoclaves. The VOC BACT emission rate will be 0.04 lb/hr for each EU IDs 77 and 81.

Step 5 – Selection of VOC BACT for Autoclaves

The Department's finding is that BACT for VOC emissions for autoclaves is as follows:

(a) VOC emissions from EU IDs 77 and 81 shall be controlled by operating and maintaining carbon adsorption systems at all times the units are in operation;

(b) VOC emissions from EU IDs 77 and 81 shall not exceed 0.04 lb/hr each averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

5.4 GHG

Possible GHG emission control technologies for autoclaves were determined based on research for similar ore autoclaves. Nevada currently has two gold mines using similar units with a total of 8 autoclaves.

Step 1 – Identification of GHG Control Technologies for Autoclaves

From research, the Department identified the following technologies as available for GHG control of autoclaves:

(a) CCS
See control description in Section 3.5.

(b) Good Operating Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible GHG Control Options for Autoclaves

CCS is a technically infeasible control technology for the stationary source for the reasons stated in Section 3.5.

Step 3 – Ranking of Remaining GHG Control Options for Autoclaves

Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

Good operating practices will reduce GHG emissions from EU IDs 77 and 81 while having minimal energy and environmental impacts.

Applicant Proposal

Donlin proposed to use good operating practices for controlling GHG emissions from the autoclaves. The GHG BACT emission limit will be 37,659 tons per year of GHG emissions combined for EU IDs 77 and 81.

Step 5 – Selection of GHG BACT for Autoclaves

The Department's finding is that BACT for GHG emissions for autoclaves is as follows:

(a) GHG emissions from EU IDs 77 and 81 shall be minimized by maintaining good operating practices at all times the units are in operation;

(b) GHG emissions from EU IDs 77 and 81 shall not exceed 37,659 tons per year combined.

6.0 Boilers and Heaters

The DGP will have three boilers (EU IDs 15 through 17) that will be fueled by both natural gas and ULSD, three heaters (EU IDs 18 through 20) that will be fueled by both natural gas and ULSD, and 19 air handler heaters (EU ID 24) that will be fueled by natural gas. ULSD will be used for EU IDs 15 through 20 when natural gas is unavailable.

EU IDs 15 and 16 are classified as process heaters and are exempt from NSPS Subpart Dc. EU IDs 17 through 20 and 24 are subject to requirements under NSPS Subpart Dc but are not subject to any NSPS emissions limits.

DGP will also have two SO_2 burners, one operating off natural gas (EU ID 21) and one off ULSD (EU ID 22), 138 building heaters (EU ID 23), seven 2.5 MMBtu/hr air handler heaters (EU ID 25), and 20 portable heaters (EU ID 26).

The boilers and heaters will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide a BACT review for each of these pollutants (except SO_2) for each fuel type.

6.1 CO

Possible CO emission control technologies for boilers and heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13, Commercial/Institutional-Sized Boilers/Furnaces (<100 MMBtu/hr), subcategories 13.31 Gaseous Fuel and Gaseous Fuel Mixtures and 13.22, Distillate Fuel Oil. The search results for boilers and heaters are summarized in Table 6-1 and Table 6-2, respectively.

Table 6-1. CO Control for Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Oxidation Catalyst	1	0.016
Good Combustion Practices & Clean Fuel	69	0.0075 – 0.087
No Control Specified	13	0.037 – 0.109

Table 6-2. CO Control for Oil-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Oxidation Catalyst	0	N/A
Good Combustion Practices & Clean Fuel	0	N/A
No Control Specified	1	0.04

Step 1 – Identification of CO Control Technologies for Boilers and Heaters
From research, the Department identified the following technologies as available for CO control of boilers and heaters with a rating of less than 100 MMBtu/hr:

(a) Oxidation Catalyst
See control description in Section 3.1.

(b) Good Combustion Practices and Clean Fuels
See control description in Section 3.1

Step 2 – Elimination of Technically Infeasible CO Control Options for Boilers and Heaters
Both control technologies listed above are technically feasible.

Step 3 – Ranking of Remaining CO Control Options for Boilers and Heaters
The following control technologies have been identified and ranked for control of CO from the boilers and heaters:

(a) Oxidation Catalyst (90% Control)

(b) Good Combustion Practices (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst would provide the best control for a boiler rated at less than 100 MMBtu/hr.

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices are the principal CO control technologies installed on boilers and heaters.

Applicant Proposal

Donlin provided combined CO and VOC economic analyses using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (catalytic oxidation) on the boilers and heaters to demonstrate that this control is not economically feasible for these units. For their economic analyses, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2021 Chemical Engineering Plant Cost Index (CEPCI) of 772.5, the default life expectancy of 20 years for the control system, and the Donlin Gold Project borrowing interest rate of 8.0 percent. A summary of Donlin's analyses are as follows: POX Boilers EU IDs 15 and 16 are shown in Table 6-3 for natural gas and Table 6-4 for ULSD, Oxygen Plant Boiler EU ID 17 in Table 6-5 for natural gas and Table 6-6 for ULSD, Carbon Elution Heater EU ID 18 in Table 6-7 for natural gas and Table 6-8 for ULSD, and the Power Plant Auxiliary Heaters EU IDs 19 and 20 in Table 6-9 for natural gas and Table 6-10 for ULSD. Note that all of these analyses are per heater for combined CO and VOC reductions. The remaining heaters and boilers are all smaller than 5 MMBtu/hr and were not analyzed.

Table 6-3: Donlin Analysis for Technically Feasible CO Controls (EU IDs 15 and 16 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.10	10.05	$471,656	$170,576	$16,980
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-4: Donlin Analysis for Technically Feasible CO Controls (EU IDs 15 and 16 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.21	20.52	$493,283	$174,091	$8,486
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-5: Donlin Analysis for Technically Feasible CO Controls (EU ID 17 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.07	7.09	$389,664	$150,442	$21,232
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-6: Donlin Analysis for Technically Feasible CO Controls (EU ID 17 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.15	14.47.	$407,532	$153,293	$10,593
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

[8] Donlin submitted cost calculation spreadsheets using EPA's Air Pollution Control Cost Manual for oxidation catalysts and selective catalytic reduction. The EPA spreadsheets are available on the following website; https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Table 6-7: Donlin Analysis for Technically Feasible CO Controls (EU ID 18 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.08	8.04	$338,800	$138,075	$17,165
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-8: Donlin Analysis for Technically Feasible CO Controls (EU ID 18 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.17	16.76	$354,332	$140,388	$8,378
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-9: Donlin Analysis for Technically Feasible CO Controls (EU IDs 19 and 20 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	6.28	$344,555	$139,444	$22,212
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-10: Donlin Analysis for Technically Feasible CO Controls (EU IDs 19 and 20 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.03	2.86	$360,366	$142,279	$49,779
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the boilers and heaters based on the excessive cost per ton of CO removed per year.

Donlin proposes the following as BACT for CO emissions from the small boilers and heaters:

(a) CO emissions from EU IDs 15 through 26 will be controlled by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) CO emissions from EU IDs 15 through 17 shall not exceed 0.074 lb/MMBtu when firing natural gas and 0.160 lb/MMBtu when firing ULSD;

(c) CO emissions from EU ID 18 shall not exceed 0.111 lb/MMBtu when firing natural gas and 0.240 lb/MMBtu when firing ULSD;

(d) CO emissions from EU IDs 19 through 22 and 24 through 26 shall not exceed 0.082 lb/MMBtu when firing natural gas and 0.038 lb/MMBtu when firing ULSD; and

(e) CO emissions from EU ID 23 shall not exceed 0.039 lb/MMBtu when firing natural gas.

Department Evaluation of BACT for CO Emissions from Small Boilers and Heaters

The Department revised the cost analyses changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams of ULSD and natural gas as opposed to coal. The Department kept the other assumptions unchanged, including the 99 percent control efficiency and the interest rate of 8%. A summary of the Department's analyses are as follows: POX Boilers EU IDs 15 and 16 are shown in Table 6-11 for natural gas and Table 6-12 for ULSD, Oxygen Plant Boiler EU ID 17 in Table 6-13 for natural gas and Table 6-14 for ULSD, Carbon Elution Heater EU ID 18 in Table 6-15 for natural gas and Table 6-16 for ULSD, and the Power Plant Auxiliary Heaters EU IDs 19 and 20 in Table 6-17 for natural gas and Table 6-18 for ULSD. Note that all these analyses are per heater for combined CO and VOC reductions. The remaining heaters and boilers are all smaller than 5 MMBtu/hr and were not analyzed.

Table 6-11: Department Analysis for Technically Feasible CO Controls (EU IDs 15 and 16 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.10	10.05	$471,656	$166,023	$16,597
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-12: Department Analysis for Technically Feasible CO Controls (EU IDs 15 and 16 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.21	20.52	$493,283	$170,067	$8,290
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-13: Department Analysis for Technically Feasible CO Controls (EU ID 17 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.07	7.09	$389,664	$147,262	$20,783
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-14: Department Analysis for Technically Feasible CO Controls (EU ID 17 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.15	14.47.	$407,532	$149,967	$10,363
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-15: Department Analysis for Technically Feasible CO Controls (EU ID 18 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.08	8.04	$338,800	$135,310	$16,821
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-16: Department Analysis for Technically Feasible CO Controls (EU ID 18 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.17	16.76	$354,332	$137,496	$8,205
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-17: Department Analysis for Technically Feasible CO Controls (EU IDs 19 and 20 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	6.28	$344,555	$136,632	$21,764
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-18: Department Analysis for Technically Feasible CO Controls (EU IDs 19 and 20 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.03	2.86	$360,366	$139,338	$48,750
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EU IDs 15 through 20 (or the smaller EUs) with economic analyses showing costs in the range of $8,205 to $48,750 per ton of pollutants removed. The Department considered the fact that that the stationary source plans to use natural gas as the primary fuel for the heaters and boilers which would result in the lowest cost per ton of pollutants removed of $16,597 for EU IDs 15 and 16, as can be seen in Table 6-11.

Step 5 – Selection of CO BACT for Small Heaters and Boilers

The Department's finding is that BACT for CO emissions from the heaters and boilers rated at less than 100 MMBtu/hr is as follows:

(a) CO emissions from EU IDs 15 through 26 will be controlled by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) CO emissions from EU IDs 15 through 17 shall not exceed 0.074 lb/MMBtu when firing natural gas and 0.160 lb/MMBtu when firing ULSD;

(c) CO emissions from EU ID 18 shall not exceed 0.111 lb/MMBtu when firing natural gas and 0.240 lb/MMBtu when firing ULSD;

(d) CO emissions from EU IDs 19 through 22 and 24 through 26 shall not exceed 0.082 lb/MMBtu when firing natural gas and 0.038 lb/MMBtu when firing ULSD;

(e) CO emissions from EU ID 23 shall not exceed 0.039 lb/MMBtu when firing natural gas; and

(f) For EU IDs 15 through 26, initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

6.2 NOx

Possible NOx emission control technologies for the boilers and heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13, Commercial/Institutional-Size Boilers/Furnaces (<100 MMBtu/hr), subcategories 13.31 Gaseous Fuel & Gaseous Fuel Mixtures and 13.22, Distillate Fuel Oil. The search results for boilers and heaters are summarized in Table 6-19 and Table 6-20, respectively.

Table 6-19. NOx Control for Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	8	0.035
Low & Ultra-Low NOx Burners	104	0.0011 - 0.18
Good Combustion Practices and Clean Fuel	16	0.035 - 0.141
Flue Gas Recirculation	7	0.011 - 0.02
No Control Specified	15	0.011 - 0.1

Table 6-20. NOx Control for Oil-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Selective Catalytic Reduction	0	N/A
Low-NOx Burners	1	0.09
Good Combustion Practices	1	No Data
No Control Specified	2	0.15 - 0.21

Step 1 – Identification of NOx Control Technologies for Boilers and Heaters

From research, the Department identified the following technologies as available for NOx control of boilers and heaters rated at 100 MMBtu/hr or less:

(a) Selective Catalytic Reduction (SCR)

See control description in Section 3.2.

(b) Low-NOx Burners (LNB)

Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible.

(c) Ultra-Low NOx Burners

Ultra-low NOx burners operate on the same principle as LNB described above but have advanced designs for achieving higher NOx destruction efficiencies. Designs that promote superior NOx destruction efficiencies often have a higher investment cost than typical LNBs. Some manufacturers of smaller heaters/boilers do not offer ultra-low NOx burners because the incremental emissions reduction is not cost effective as compared to standard LNBs. However, the Department's search of the RBLC database found 24 gas-fired heaters/boilers smaller than 100 MMBtu/hr using ultra-low NOx burners to control NOx emissions, including boilers with heat inputs of less than 20 MMBtu/hr.

(d) Flue Gas Recirculation (FGR)

FGR involves recycling a portion of the combustion gases from the stack to the boiler combustion air intake. The combustion products are low in oxygen, and when mixed with the combustion air, lower the overall excess oxygen concentration. This process acts as a heat sink to lower the peak flame temperature as well as the residence time at peak flame temperature. These effects work together to limit thermal NOx formation. The typical NOx removal efficiency using FGR is 20-25%.

(e) Good Combustion Practices (GCP) and Clean Fuel
See control description in Section 3.1. The Department's search of the RBLC database indicated that GCPs and clean fuel are used to control NOx emissions for gas-fired boilers rated at less than 100 MMBtu/hr.

Step 2 – Elimination of Technically Infeasible NOx Control Options for Boilers and Heaters
Low-NOx burners for dual-fuel fired boilers that meet the project specifications are not available for EU IDs 15 through 20 and are therefore considered technically infeasible.

Step 3 – Ranking of Remaining NOx Control Options for Boilers and Heaters
The following control technologies have been identified and ranked for control of NOx from the boilers and heaters:

(a) SCR	(70 - 90% Control)
(b) Flue Gas Recirculation	(20% - 25% Control)
(c) Good Combustion Practices	(Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for small utility heaters. No unusual energy impacts were identified with the addition of SCR to the heaters. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

RBLC Review
A review of similar units in the RBLC indicates that low-NOx and ultra-low NOx burners are the principal NOx control technologies installed on boilers and heaters rated at 100 MMBtu/hr or less.

Applicant Proposal
Donlin has proposed FGR for the EUs that are capable of using this control technology (EU IDs 15 through 18). Additionally, Donlin provided economic analyses using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (SCR) on the boilers and heaters to demonstrate that this control is not economically feasible for these units. For their economic analyses, Donlin used the EPA default emission reduction efficiency of 85 percent, the 2021 CEPCI of 772.5, the default life expectancy of 25 years for the control system, and the Donlin Gold Project borrowing interest rate of 8.0 percent. A summary of Donlin's analyses are as follows: POX Boilers EU IDs 15 and 16 are shown in Table 6-21 for natural gas and Table 6-22 for ULSD, Oxygen Plant Boiler EU ID 17 in Table 6-23 for natural gas and Table 6-24 for ULSD, Carbon Elution Heater EU ID 18 in Table 6-25 for natural gas and Table 6-26 for ULSD, and the Power Plant Auxiliary Heaters EU IDs 19 and 20 in Table 6-27 for natural gas and Table 6-28 for ULSD. Note that all of these analyses are per heater and include the higher capital investment cost for SCR compatible with natural gas (as opposed to the lower capital investment cost for SCR compatible with ULSD) as these are dual fuel-fired units that will primarily combust natural gas. The remaining heaters and boilers are all smaller than 5 MMBtu/hr and were not analyzed.

Table 6-21: Donlin Analysis for Technically Feasible NOx Controls (EU IDs 15 and 16 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	0.93	5.28	$1,489,017	$163,685	$31,000
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-22: Donlin Analysis for Technically Feasible NOx Controls (EU IDs 15 and 16 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	2.53	14.33	$1,489,017	$168,101	$11,732
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-23: Donlin Analysis for Technically Feasible NOx Controls (EU ID 17 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	0.66	3.72	$1,186,771	$129,710	$34,827
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-24: Donlin Analysis for Technically Feasible NOx Controls (EU ID 17 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	1.78	10.11	$1,186,771	$132,825	$13,143
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-25: Donlin Analysis for Technically Feasible NOx Controls (EU ID 18 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	0.64	3.61	$1,005,341	$109,916	$30,486
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-26: Donlin Analysis for Technically Feasible NOx Controls (EU ID 18 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	2.35	13.31	$1,005,341	$114,651	$8,617
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-27: Donlin Analysis for Technically Feasible NOx Controls (EU IDs 19 and 20 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	1.06	6.02	$1,026,386	$113,369	$18,824
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-28: Donlin Analysis for Technically Feasible NOx Controls (EU IDs 19 and 20 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	1.67	9.46	$1,026,386	$115,047	$12,161
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Donlin contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR on the boilers and heaters based on the excessive cost per ton of NOx removed per year.

Donlin proposes the following as BACT for NOx emissions from the small boilers and heaters:

(a) NOx emissions from EU IDs 15 through 18 will be controlled by operating and maintaining flue gas recirculation and good combustion practices at all times the units are in operation;

(b) NOx emissions from EU IDs 19 through 26 will be controlled by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(c) NOx emissions from EU IDs 15 through 17 shall not exceed 0.048 lb/MMBtu when firing natural gas and 0.131 lb/MMBtu when firing ULSD;

(d) NOx emissions from EU ID 18 shall not exceed 0.061 lb/MMBtu when firing natural gas and 0.223 lb/MMBtu when firing ULSD;

(e) NOx emissions from EU IDs 19 through 22 and 24 through 26 shall not exceed 0.098 lb/MMBtu when firing natural gas and 0.154 lb/MMBtu when firing ULSD;

(f) NOx emissions from EU ID 23 shall not exceed 0.092 lb/MMBtu when firing natural gas.

Department Evaluation of BACT for NOx Emissions from Small Boiler and Heaters

The Department revised the cost analyses changing the removal efficiency from 85 percent to 90 percent to reflect the higher removal efficiency of SCR control systems currently used by industry. The Department kept the other assumptions unchanged including the 25-year estimated life span of the control equipment and the interest rate of 8%. A summary of the Department's analyses are as follows: EU IDs 15 and 16 are shown in Table 6-29 for natural gas and Table 6-30 for ULSD, Oxygen Plant Boiler EU ID 17 in Table 6-31 for natural gas and Table 6-32 for ULSD, Carbon Elution Heater EU ID 18 in Table 6-33 for natural gas and Table 6-34 for ULSD, and the Power Plant Auxiliary Heaters EU IDs 19 and 20 in Table 6-35 for natural gas and Table 6-36 for ULSD. Note that all of these analyses are per heater and include the higher capital investment cost for SCR compatible with natural gas (as opposed to the lower capital investment cost for SCR compatible with ULSD) as these are dual fuel-fired units that will primarily combust natural gas. The remaining heaters and boilers are all smaller than 5 MMBtu/hr and were not analyzed.

Table 6-29: Department Analysis for Technically Feasible NOx Controls (EU IDs 15 and 16 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	0.62	5.59	$1,489,017	$163,948	$29,325
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-30: Department Analysis for Technically Feasible NOx Controls (EU IDs 15 and 16 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	1.69	15.17	$1,489,017	$168,623	$11,115
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-31: Department Analysis for Technically Feasible NOx Controls (EU ID 17 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	0.44	3.94	$1,186,771	$129,895	$32,939
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-32: Department Analysis for Technically Feasible NOx Controls (EU ID 17 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	1.19	10.70	$1,186,771	$133,193	$12,447
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-33: Department Analysis for Technically Feasible NOx Controls (EU ID 18 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	0.42	3.82	$1,005,341	$110,080	$28,836
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-34: Department Analysis for Technically Feasible NOx Controls (EU ID 18 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR (FGR Baseline)	1.57	14.09	$1,005,341	$115,092	$8,169
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-35: Department Analysis for Technically Feasible NOx Controls (EU IDs 19 and 20 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.71	6.38	$1,026,386	$113,604	$17,815
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-36: Department Analysis for Technically Feasible NOx Controls (EU IDs 19 and 20 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	1.11	10.02	$1,026,386	$115,381	$11,519
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of SCR as BACT for EU IDs 15 through 20 (or the smaller EUs) with economic analyses showing costs in the range of $8,169 to $32,939 per ton of pollutants removed. The Department considered the fact that that the stationary source plans to use natural gas as the primary fuel for the heaters and boilers which would result in the lowest cost per ton of NOx removed of $17,815 for EU IDs 19 and 20, as can be seen in Table 6-35.

Step 5 – Selection of NOx BACT for Small Heaters and Boilers

The Department's finding is that BACT for NOx emissions from the heaters and boilers rated at less than 100 MMBtu/hr is as follows:

(a) NOx emissions from EU IDs 15 through 18 will be controlled by operating and maintaining flue gas recirculation and good combustion practices at all times the units are in operation;

(b) NOx emissions from EU IDs 19 through 26 will be controlled by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(c) NOx emissions from EU IDs 15 through 17 shall not exceed 0.048 lb/MMBtu when firing natural gas and 0.131 lb/MMBtu when firing ULSD;

(d) NOx emissions from EU ID 18 shall not exceed 0.061 lb/MMBtu when firing natural gas and 0.223 lb/MMBtu when firing ULSD;

(e) NOx emissions from EU IDs 19 through 22 and 24 through 26 shall not exceed 0.098 lb/MMBtu when firing natural gas and 0.154 lb/MMBtu when firing ULSD;

(f) NOx emissions from EU ID 23 shall not exceed 0.092 lb/MMBtu when firing natural gas; and

(g) For EU IDs 15 through 26, initial compliance with the proposed NOx emission limits will be demonstrated by conducting a performance test to obtain an emission rate or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

6.3 Particulates

Possible particulate emission control technologies for the boilers and heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13, Commercial/Institutional-Size Boilers/Furnaces (<100 MMBtu/hr), subcategories 13.31 Gaseous Fuel & Gaseous Fuel Mixtures and 13.22, Distillate Fuel Oil. The search results for boilers and heaters are summarized in Table 6-37 and Table 6-38, respectively.

Table 6-37. Particulate Control for Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices and Clean Fuel	180	0.0004 - 0.0175
No Control Specified	20	0.005 - 0.008

Table 6-38. Particulate Control for Oil-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices and Clean Fuel	6	0.01 - 0.02
No Control Specified	2	0.012 - 0.018

Step 1 – Identification of Particulate Control Technologies for Boilers and Heaters

From research, the Department identified the following technologies as available for particulate control of boilers and heaters rated at 100 MMBtu/hr or less:

(a) Good Combustion Practices (GCPs) and Clean Fuel

See control description in Section 3.1. The Department's search of the RBLC database indicated that GCPs and clean fuel are used to control particulate emissions from boilers rated at less than 100 MMBtu/hr.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Boilers and Heaters
The only control technologies identified are technically feasible for small boilers and heaters.

Step 3 – Ranking of Remaining Particulate Control Options for Boilers and Heaters
Donlin has accepted the only feasible control options. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Use of clean fuel and good combustion practices are the most effective controls for particulates from natural gas and ULSD fired boilers and heaters rated at 100 MMBtu/hr or less.

RBLC Review
A review of similar units in the RBLC indicates that use of clean fuels and good combustion practices are the principal control methods for particulates from boilers firing natural gas or ULSD rated at 100 MMBtu/hr or less.

Applicant Proposal
Donlin proposes the following as BACT for particulate emissions from the small boilers and heaters:

(a) Particulate emissions from the operation of EU IDs 15 through 26 will be minimized by maintaining good combustion practices and burning either ULSD or natural gas at all times the units are in operation; and

(b) NOx emissions from EU IDs 15 through 26 will not exceed 0.0075 lb/MMBtu when firing natural gas and 0.0254 lb/MMBtu when firing ULSD.

Step 5 – Selection of Particulate BACT for Small Heaters and Boilers
The Department's finding is that BACT for particulate emissions from the heaters and boilers rated at less than 100 MMBtu/hr is as follows:

(a) Particulate emissions from EU IDs 15 through 26 will be controlled by maintaining good combustion practices and burning either ULSD or natural gas at all times the units are in operation;

(b) Particulate emissions from EU IDs 15 through 26 will not exceed 0.0075 lb/MMBtu when firing natural gas and 0.0254 lb/MMBtu when firing ULSD averaged over a 3-hour period; and

(c) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

6.4 VOC

Possible VOC emission control technologies for the boilers and heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13, Commercial/Institutional-Size Boilers/Furnaces (<100 MMBtu/hr), subcategories 13.31 Gaseous Fuel & Gaseous Fuel Mixtures and 13.22, Distillate Fuel Oil. The search results for boilers and heaters are summarized in Table 6-39 and Table 6-40, respectively.

Table 6-39. VOC Control for Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits
Oxidation Catalyst	3	0.27 g/hp 13.37 lb/hr
Good Combustion Practices and Clean Fuels	71	0.0014 - 0.054 lb/MMBtu
No Control Specified	6	0.004 - 0.0054 lb/MMBtu

Table 6-40. VOC Control for Oil-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Good Combustion Practices	1	0.0019
No Control Specified	1	No Data

Step 1 – Identification of VOC Control Technologies for Boilers and Heaters
From research, the Department identified the following technologies as available for VOC control of boilers and heaters rated at 100 MMBtu/hr or less:

(a) Oxidation Catalyst
See control description in Section 3.1.

(b) Good Combustion Practices and Clean Fuels
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible VOC Control Options for Boilers and Heaters
Both control technologies are technically feasible for VOC control.

Step 3 – Ranking of Remaining VOC Control Options for Boilers and Heaters
The following control technologies have been identified and ranked for control of VOC from the boilers and heaters:

(a) Oxidation Catalyst (70 - 90% Control)

(b) GCPs and Clean Fuels (Less than 70% Control)

Step 4 – Evaluate the Most Effective Controls
An oxidation catalyst would provide the best VOC control for boilers and heaters rated at less than 100 MMBtu/hr.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principal control method for VOC from boilers and heaters rated at 100 MMBtu/hr or less.

Applicant Proposal
Donlin provided combined CO and VOC economic analyses using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (catalytic oxidation) on the boilers and heaters to demonstrate that this control is not economically feasible for these units. A summary of Donlin's analyses are as follows: POX Boilers EU IDs 15 and 16 are shown in Table 6-41 for natural gas and Table 6-42 for ULSD, Oxygen Plant Boiler EU ID 17 in Table 6-43 for natural gas and Table 6-44 for ULSD, Carbon Elution Heater EU ID 18 in Table 6-45 for natural gas and Table 6-46 for ULSD, and the Power Plant Auxiliary Heaters EU IDs 19 and 20 in Table 6-47 for natural gas and Table 6-48 for ULSD. Note that all of these analyses are per

heater for combined CO and VOC reductions. The remaining heaters and boilers are all smaller than 5 MMBtu/hr and were not analyzed.

Table 6-41: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 15 and 16 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.10	10.05	$471,656	$170,576	$16,980
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-42: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 15 and 16 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.21	20.52	$493,283	$174,091	$8,486
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-43: Donlin Analysis for Technically Feasible VOC Controls (EU ID 17 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.07	7.09	$389,664	$150,442	$21,232
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-44: Donlin Analysis for Technically Feasible VOC Controls (EU ID 17 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.15	14.47.	$407,532	$153,293	$10,593
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-45: Donlin Analysis for Technically Feasible VOC Controls (EU ID 18 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.08	8.04	$338,800	$138,075	$17,165
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-46: Donlin Analysis for Technically Feasible VOC Controls (EU ID 18 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.17	16.76	$354,332	$140,388	$8,378
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-47: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 19 and 20 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	6.28	$344,555	$139,444	$22,212
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 6-48: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 19 and 20 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.03	2.86	$360,366	$142,279	$49,779
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the boilers and heaters based on the excessive cost per ton of VOC removed per year.

Donlin proposes the following as BACT for VOC emissions from the small boilers and heaters:

(a) VOC emissions from EU IDs 15 through 26 will be controlled by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) VOC emissions from EU IDs 15 through 21 and 23 through 25 shall not exceed 0.0054 lb/MMBtu when firing natural gas and 0.00154 lb/MMBtu when firing ULSD; and

(c) VOC emissions from EU IDs 22 and 26 shall not exceed 0.0026 lb/MMBtu when firing ULSD.

Department Evaluation of BACT for VOC Emissions from Small Boiler and Heaters

The Department revised the cost analyses changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams from the combustion of ULSD and natural gas as opposed to coal. The Department kept the other assumptions unchanged including the 99 percent control efficiency and the interest rate of 8%, which is the estimated borrowing cost for the Donlin Gold Project. A summary of the Department's analyses are as follows: POX Boilers EU IDs 15 and 16 are shown in Table 6-49 for natural gas and Table 6-50 for ULSD, Oxygen Plant Boiler EU ID 17 in Table 6-51 for natural gas and Table 6-52 for ULSD, Carbon Elution Heater EU ID 18 in Table 6-53 for natural gas and Table 6-54 for ULSD, and the Power Plant Auxiliary Heaters EU IDs 19 and 20 in Table 6-55 for natural gas and Table 6-56 for ULSD. Note that all these analyses are per heater for combined CO and VOC reductions. The remaining heaters and boilers are all smaller than 5 MMBtu/hr and were not analyzed.

Table 6-49: Department Analysis for Technically Feasible VOC Controls (EU IDs 15 and 16 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.10	10.05	$471,656	$166,023	$16,597
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-50: Department Analysis for Technically Feasible VOC Controls (EU IDs 15 and 16 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.21	20.52	$493,283	$170,067	$8,290
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-51: Department Analysis for Technically Feasible VOC Controls (EU ID 17 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.07	7.09	$389,664	$147,262	$20,783
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-52: Department Analysis for Technically Feasible VOC Controls (EU ID 17 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.15	14.47.	$407,532	$149,967	$10,363
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-53: Department Analysis for Technically Feasible VOC Controls (EU ID 18 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.08	8.04	$338,800	$135,310	$16,821
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-54: Department Analysis for Technically Feasible VOC Controls (EU ID 18 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.17	16.76	$354,332	$137,496	$8,205
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-55: Department Analysis for Technically Feasible VOC Controls (EU IDs 19 and 20 – Natural Gas)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	6.28	$344,555	$136,632	$21,764
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 6-56: Department Analysis for Technically Feasible VOC Controls (EU IDs 19 and 20 – ULSD)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.03	2.86	$360,366	$139,338	$48,750
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EU IDs 15 through 20 (or the smaller EUs) with economic analyses showing costs in the range of $8,205 to $48,750 per ton of pollutants removed. The Department considered the fact that that the stationary source plans to use natural gas as the primary fuel for the heaters and boilers which would result in the lowest cost per ton of pollutants removed of $16,597 for EU IDs 15 and 16, as can be seen in Table 6-49.

Step 5 – Selection of VOC BACT for Small Heaters and Boilers

The Department's finding is that BACT for VOC emissions from the heaters and boilers rated at less than 100 MMBtu/hr is as follows:

(a) VOC emissions from EU IDs 15 through 26 will be controlled by maintaining good combustion practices and burning clean fuels at all times the units are in operation;

(b) VOC emissions from EU IDs 15 through 21 and 23 through 25 shall not exceed 0.0054 lb/MMBtu when firing natural gas and 0.00154 lb/MMBtu when firing ULSD;

(c) VOC emissions from EU IDs 22 and 26 shall not exceed 0.0026 lb/MMBtu when firing ULSD; and

(d) For EU IDs 15 through 26, initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

6.5 GHG

Possible GHG emission control technologies for the boilers and heaters were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13, Commercial/Institutional-Size Boilers/Furnaces (<100 MMBtu/hr), subcategories 13.31 Gaseous Fuel & Gaseous Fuel Mixtures and 13.22, Distillate Fuel Oil. The search results for boilers and heaters are summarized in Table 6-57 and Table 6-58, respectively.

Table 6-57. GHG Control for Gas-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits (tpy)
Good Combustion Practices and Clean Fuel	72	30 – 455,475
No Control Specified	18	625 – 131,405

Table 6-58. GHG Control for Oil-Fired Boilers and Heaters

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	1	No Data
No Control Specified	2	45,537 tpy 203.8 lb/1,000 lb of steam

Step 1 – Identification of GHG Control Technologies for Boilers and Heaters

From research, the Department identified the following technologies as available for VOC control of boilers and heaters rated at 100 MMBtu/hr or less:

(a) CCS
See control description in Section 3.5.

(b) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Boilers and Heaters

CCS is a technically infeasible control technology for the stationary source for the reasons stated in Section 3.5.

Step 3 – Ranking of Remaining GHG Control Options for Boilers and Heaters

Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

Good combustion practices will reduce GHG emissions from EU IDs 15 through 26 while having minimal energy and environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principal control method for GHG from boilers and heaters rated at 100 MMBtu/hr or less.

Applicant Proposal
Donlin proposed to use good combustion practices for EU IDs 15 through 26 as BACT for reducing GHG emissions from combustion of natural gas and ULSD. The BACT GHG emission limit will be 176,775 tons per year combined for EU IDs 15 through 26.

Step 5 – Selection of GHG BACT for Small Boilers and Heaters
The Department's finding is that BACT for GHG emissions from the boilers and heaters rated at less than 100 MMBtu/hr is as follows:

(a) GHG emissions from EU IDs 15 through 26 shall be minimized by maintaining good combustion practices and burning clean fuels at all times the units are in operation; and

(b) GHG emissions from EU IDs 15 through 26 shall not exceed 176,775 tons per year combined.

7.0 Limited Use Diesel Engines

Donlin will have several emergency engines on site that include two black start generators rated at 600 kW (EU IDs 29 and 30), four camp site emergency engines rated at 1,500 kW (EU IDs 31 through 34), and three fire pump engines rated at 252 hp (EU IDs 35 through 37). EU IDs 29 through 37 are all considered limited use engines.

The limited use engines will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide a BACT review for each of these pollutants (except SO_2).

7.1 CO

Possible CO emission control technologies for the limited use engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 Large (>500 hp) and 17.210 Small (≤500 hp), Fuel Oil Burning Internal Combustion Engines. The search results for the large and small diesel engines are summarized in Tables 7-1 and 7-2, respectively.

Table 7-1. CO Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Oxidation Catalyst	2	0.096 -2.4
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	72	0.33 - 2.7
Limited Use	5	0.37 - 1.9
No Control Specified	13	0.19 - 1.9

Table 7-2. CO Control for Small Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	70	0.67 – 11
Limited Use	5	1.6 - 3.5
No Control Specified	11	0.7 - 5

Step 1 – Identification of CO Control Technologies for Limited Use Diesel Engines

From research, the Department identified the following technologies as available for CO control of the limited use diesel engines:

(a) Oxidation Catalyst
See control description in Section 3.1.

(b) Good Combustion Practices and Clean Fuel
See control description in Section 3.1.

(c) Federal Emission Standards
See control description in Section 3.1. The limited use diesel engines are required to comply with the federal emissions standards in NSPS Subpart IIII.

(d) Limited Operation
See control description in Section 3.1 The Department considers limited operation a technically feasible control technology for the limited use diesel engines.

Step 2 – Elimination of Technically Infeasible CO Control Options for Limited Use Diesel Engines
All control technologies listed above are technically feasible.

Step 3 – Ranking of Remaining CO Control Options for Limited Use Diesel Engines
The following control technologies have been identified and ranked for control of CO from the emergency engines:

(a)	Limited Use	(94% Control)
(b)	Oxidation Catalyst	(90% Control)
(c)	Good Combustion Practices	(Less than 90% Control)
(d)	Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls
Limited use and catalytic oxidation are the most effective controls at reducing CO emissions from EU IDs 29 through 37 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that catalytic oxidation add-on control technology is not practical for the smaller 252 hp limited use engines EU IDs 35 through 37 that have minimal emissions. Based on the small potential to emit associated with these units (0.49 tpy of combined CO and VOC emissions per engine), catalytic oxidation is not a cost-effective control technology for the smaller limited use engines. However, the Department did find instances of oxidation catalysts used on larger engines in the RBLC, and EU IDs 29 and 30 have potential combined CO and VOC emissions of 1.58 tpy for each engine and EU IDs 31 through 34 have potential combined CO and VOC emissions of 3.95 tpy for each engine. Therefore, catalytic oxidation is advanced for the larger limited use engines EU IDs 29 through 34.

Applicant Proposal
Donlin provided combined CO and VOC economic analyses using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (catalytic oxidation) on the limited use diesel engines to demonstrate that this control is not economically feasible for

these units. For their economic analyses, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2021 CEPCI of 772.5, the default life expectancy of 20 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 500 hours of operation per year for the black start and emergency diesel generators. A summary of Donlin's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-3 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-4. Note that all these analyses are per engine for combined CO and VOC emissions reductions. The remaining limited use diesel engines EU IDs 35 through 37 all have less than 1.0 tpy each of combined CO and VOC emissions and were not analyzed.

Table 7-3: Donlin Analysis for Technically Feasible CO Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.02	1.57	$246,464	$40,161	$25,536
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 7-4: Donlin Analysis for Technically Feasible CO Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.04	3.93	$406,923	$64,493	$16,403
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the limited use diesel engines based on the excessive cost per ton of CO removed per year.

Donlin proposes the following as BACT for CO emissions from the limited use diesel engines:

(a) CO emissions from EU IDs 29 through 37 will be controlled by maintaining good combustion practices at all times the units are in operation and installing engines certified to meet NSPS Subpart IIII; and

(b) CO emissions from EU IDs 29 through 37 shall not exceed 4.38 g/kW-hr.

Department Evaluation of BACT for CO Emissions from Limited Use Diesel Engines

The Department revised the cost analyses changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams from the combustion of ULSD as opposed to coal. The Department kept the other assumptions unchanged including the 99 percent control efficiency and the interest rate of 8% and assumed 500 hours per year of emergency operation. A summary of the Department's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-5 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-6. Note that all these analyses are per engine for combined CO and VOC emissions reductions. The remaining limited use diesel engines EU IDs 35 through 37 all have less than 1.0 tpy each of combined CO and VOC emissions and were not analyzed.

Table 7-5: Department Analysis for Technically Feasible CO Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.02	1.57	$246,464	$38,149	$24,257
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 7-6: Department Analysis for Technically Feasible CO Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.04	3.93	$406,923	$61,173	$15,559
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EU IDs 29 through 34 (or the smaller EU IDs 35 through 37) with economic analyses showing costs in the range of $15,559 to $24,257 per ton of pollutants removed.

Step 5 – Selection of CO BACT for Limited Use Diesel Engines

The Department's finding is that BACT for CO emissions from the limited use diesel engines is as follows:

(a) CO emissions from EU IDs 29 through 37 will be controlled by maintaining good combustion practices at all times the units are in operation and installing engines certified to meet NSPS Subpart IIII;

(b) CO emissions from EU IDs 29 through 37 shall not exceed 4.38 g/kW-hr[9]; and

(c) For EU IDs 29 through 37, initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

7.2 NOx

Possible NOx emission control technologies for limited use engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 Large (>500 hp) and 17.210 Small (≤500 hp), Fuel Oil Burning Internal Combustion Engines. The search results for the large and small diesel engines are summarized in Tables 7-7 and 7-8, respectively.

Table 7-7. NOx Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Selective Catalytic Reduction	1	0.5
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	70	0.4 - 25
Fuel Injection Timing Retard	6	6.0 - 13
Limited Use	2	4.4 - 6.4
No Control Specified	9	3.8 - 7.1

[9] CO emissions of 4.38 g/kW-hr is equivalent to the EPA Nonroad Tier 2 standard for EUs 29 – 34 and Table 4 to NSPS Subpart IIII for EUs 35 – 37, both with a 1.25 not to exceed factor of safety.

Table 7-8. NOx Control for Small Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Federal Emission Standards, Clean Fuel, Limited Use, & Good Combustion Practices	64	0.4 - 26
No Control Specified	8	3.82 - 18.85

Step 1 – Identification of NOx Control Technologies for Limited Use Diesel Engines

From research, the Department identified the following technologies as available for NOx control of limited use diesel engines:

(a) **Selective Catalytic Reduction (SCR)**
See control description in Section 3.2.

(b) Good Combustion Practices and Clean Fuel

See control description in Section 3.1.

(c) Federal Emission Standards

See control description in Section 3.1. The limited use diesel engines are required to comply with the federal emissions standards in NSPS Subpart IIII.

(d) Ignition Timing Retard (ITR)

See control description in Section 3.2. Due to the increase in the particulate matter emissions resulting from ITR, this technology will not be carried forward.

(e) Limited Operation

See control description in Section 3.1 The Department considers limited operation a technically feasible control technology for the limited use diesel engines.

Step 2 – Elimination of Technically Infeasible NOx Control Options for Limited Use Diesel Engines
As explained in Step 1, the Department does not consider ignition timing retard as a technically feasible control technology for the large engines.

Step 3 – Ranking of Remaining NOx Control Options for Black Start and Emergency Diesel Engines
The following control technologies have been identified and ranked for control of NOx from the engines:

(a) Limited Use (94% Control)

(b) SCR (90% Control)

(c) GCPs and Clean Fuel (Less than 80% Control)

(d) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
Limited use and SCR are the most effective controls at reducing NOx emissions from EU IDs 29 through 37 while having minimal energy and environmental impacts. Environmental impacts are that the SCR adds exhaust back pressure that decreases the engine's efficiency and requiring additional fuel consumption; the SCR catalyst does need to be replaced and recycled as necessary, and the SCR will emit ammonia from the ammonia slip of the system.

RBLC Review

A review of similar units in the RBLC indicates that SCR add-on control technology is not practical for the smaller 252 hp limited use engines EU IDs 35 through 37 that have minimal emissions. Based on the small potential to emit associated with these units (0.49 tpy of NOx each), SCR is not a cost-effective control technology for the smaller limited use engines. However, the Department did find instances of SCR used on larger engines in the RBLC, and EU IDs 29 and 30 have potential NOx emissions of 2.51 tons each and EU IDs 31 through 34 have potential NOx emissions of 6.28 tpy each. Therefore, SCR is advanced for the larger limited use engines EU IDs 29 through 34.

Applicant Proposal

Donlin provided economic analyses using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (SCR) on the limited use diesel engines to demonstrate that this control is not economically feasible for these units. For their economic analyses, Donlin used the EPA default emission reduction efficiency of 85 percent, the 2021 CEPCI of 772.5, the default life expectancy of 25 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 500 hours of operation per year for the black start and emergency diesel generators. A summary of Donlin's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-9 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-10. Note that all these analyses are per engine for NOx emissions reductions. The remaining limited use diesel engines EU IDs 35 through 37 have less than 1.0 tpy each for NOx emissions and were not analyzed.

Table 7-9: Donlin Analysis for Technically Feasible NOx Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.40	2.25	$421,682	$42,991	$19,118
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 7-10: Donlin Analysis for Technically Feasible NOx Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.99	5.62	$762,516	$78,444	$13,953
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Donlin contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR on the limited use diesel engines based on the excessive cost per ton of NOx removed per year.

Donlin proposes the following as BACT for NOx emissions from the limited use diesel engines:

(a) NOx emissions from EU IDs 29 through 37 will be controlled purchasing engines certified to meet EPA federal emissions standards in NSPS Subpart IIII, by combusting clean fuel, and maintaining good combustion practices at all times the units are in operation;

(b) NOx + non-methane hydrocarbons (NMHC) emissions from EU IDs 29 through 34 will not exceed 8.0 g/kW-hr (EPA Nonroad Tier 2 emissions standard plus 25% not to exceed factor of safety); and

(c) NOx + NMHC emissions from EU IDs 35 through 37 will not exceed 5.0 g/kW-hr (Table 4 to NSPS Subpart IIII plus 25% not to exceed factor of safety).

Department Evaluation of BACT for NOx Emissions from Limited Use Diesel Engines

The Department revised the cost analyses changing the removal efficiency from 85 percent to 90 percent to reflect the higher removal efficiency of SCR control systems currently used by industry. The Department kept the other assumptions unchanged including the 25-year estimated life span of the control equipment, the interest rate of 8%, and assumed 500 hours per year of emergency operation. A summary of the Department's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-11 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-12. Note that all these analyses are per engine for NOx emissions reductions, which conservatively assumes that 95% of all NOx + NMHC emissions are attributable to NOx. The remaining limited use diesel engines EU IDs 35 through 37 have less than 1.0 tpy each for NOx emissions and were not analyzed.

Table 7-11: Department Analysis for Technically Feasible NOx Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.26	2.38	$421,682	$43,055	$18,083
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 7-12: Department Analysis for Technically Feasible NOx Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.66	5.95	$762,516	$78,603	$13,205
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of NOx reduction does not justify the use of SCR as BACT for EU IDs 29 through 34 (or the smaller EU IDs 35 through 37) with economic analyses showing costs in the range of $13,083 to $18,083 per ton of pollutants removed.

Step 5 – Selection of NOx BACT for Limited Use Diesel Engines

The Department's finding is that BACT for NOx emissions from the limited use diesel engines is as follows:

(a) NOx emissions from EU IDs 29 through 37 will be controlled purchasing engines certified to meet EPA federal emissions standards in NSPS Subpart IIII and maintaining good combustion practices at all times the units are in operation;

(b) NOx + NMHC emissions from EU IDs 29 through 34 will not exceed 8.0 g/kW-hr (EPA Nonroad Tier 2 emissions standard for NOx + NMHC plus 25% not to exceed factor of safety);

(c) NOx + NMHC emissions from EU IDs 35 through 37 will not exceed 5.0 g/kW-hr (Table 4 to NSPS Subpart IIII emissions standard for NOx + NMHC plus 25% not to exceed factor of safety); and

(d) For EU IDs 29 through 37, initial compliance with the proposed NOx + NMHC emission limits will be demonstrated by conducting a performance test to obtain an emission rate or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

7.3 Particulates

Possible particulate emission control technologies for limited use engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 Large (>500 hp) and 17.210 Small (≤500 hp), Fuel Oil Burning Internal Combustion Engines. The search results for the large and small diesel engines are summarized in Tables 7-13 and 7-14, respectively.

Table 7-13. Particulate Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Diesel Particulate Filter	3	0.52 – 0.54 (lb/hr) 0.20 (g/kW-hr)
Clean Fuel, Good Combustion Practices, Limited Operation & Federal Emissions Standards	84	0.030 – 0.54 (g/kW-hr)
No Control Specified	26	0.034 – 0.27 (g/kW-hr)

Table 7-14. Particulate Control for Small Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits
Diesel Particulate Filter	3	0.66 (lb/hr) 0.54 (g/kW-hr)
Clean Fuel Good Combustion Practices, Limited Operation, and Federal Emission Standards	116	0.02 - 0.5 (g/kW-hr)
No Control Specified	13	0.2 – 1.34 (g/kW-hr)

Step 1 – Identification of Particulate Control Technologies for Limited Use Diesel Engines

From research, the Department identified the following technologies as available for particulate control of diesel engines:

(a) **Diesel Particulate Filter (DPF)**
See control description in Section 3.3.

(b) **Good Combustion Practices**
See control description in Section 3.1.

(c) **Limited Use**
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Limited Use Diesel Engines

All control technologies identified are technically feasible to control particulate emissions from the diesel engines.

Step 3 – Ranking of Remaining Particulate Control Options for Limited Use Diesel Engines

The following control technologies have been identified and ranked for control of particulate emissions from the diesel engines.

(a) Limited Operation (94% Control)

(b) Diesel Particulate Filters (85% Control)

(c) Good Combustion Practices (Less than 40% Control)

(d) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
Limited operation and diesel particulate filters will reduce particulate emissions from EU IDs 29 through 37 while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that federal emission standards, good combustion practices, and burning of ULSD fuel are the principle particulate control technologies installed on diesel engines.

Applicant Proposal
Donlin provided economic analyses for the installation of the most effective control technology (DPF) on the limited use diesel engines to demonstrate that this control is not economically feasible for these units. For their economic analyses, Donlin used an estimate of 90 percent control efficiency, a vendor estimate of $43.50/ekW for the DPF, an estimated life expectancy of 10 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 500 hours of operation per year for the black start and emergency diesel generators. A summary of Donlin's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-15 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-16. Note that all these analyses are per engine for particulate emissions reductions. The remaining limited use diesel engines EU IDs 35 through 37 have less than 0.1 tpy each for particulate emissions and were not analyzed.

Table 7-15: Donlin Analysis for Technically Feasible Particulate Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.008	0.074	$45,923	$9,431	$126,749
Capital Recovery Factor = 0.1490 (8% for a 10-year life cycle)					

Table 7-16: Donlin Analysis for Technically Feasible Particulate Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.021	0.186	$114,807	$22,452	$120,700
Capital Recovery Factor = 0.1490 (8% for a 10-year life cycle)					

Donlin contends that the economic analysis indicates the level of particulate emissions reduction does not justify the use of DPF on the limited use diesel engines based on the excessive cost per ton of particulate emissions removed per year.

Donlin proposes the following as BACT for particulate emissions from the limited use diesel engines:

(a) Particulate emissions from EU IDs 29 through 37 will be controlled purchasing engines certified to meet EPA federal emissions standards in NSPS Subpart IIII, by combusting clean fuel, and maintaining good combustion practices at all times the units are in operation; and

(b) Particulate emissions from EU IDs 29 through 37 will not exceed 0.25 g/kW-hr.

Department Evaluation of BACT for Particulate Emissions from Limited Use Diesel Engines

The Department revised the cost analyses changing the estimated equipment life to 20 years to reflect an estimated longer life for the DPF system only operating 500 hours per year, which is the equivalent of 10,000 hours. The Department kept the other assumptions unchanged including the 90 percent control efficiency and the interest rate of 8% and assumed 500 hours per year of emergency operation. A summary of the Department's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-17 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-18. Note that all these analyses are per engine for particulate emissions reductions. The remaining limited use diesel engines EUs 35 through 37 all have less than 0.1 tpy each of particulate emissions and were not analyzed.

Table 7-17: Department Analysis for Technically Feasible Particulate Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.008	0.074	$45,923	$7,264	$97,631
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 7-18: Department Analysis for Technically Feasible Particulate Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
DPF	0.021	0.186	$114,807	$17,036	$91,583
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

The Department's economic analysis indicates the level of particulate emissions reduction does not justify the use of DPF as BACT for EU IDs 29 through 34 (or the smaller EU IDs 35 through 37) with economic analyses showing costs in the range of $91,583 to $97,631 per ton of pollutants removed.

Step 5 – Selection of Particulate BACT for Limited Use Diesel Engines

The Department's finding is that BACT for particulate emissions from the limited use diesel engines is as follows:

(a) Particulate emissions from EU IDs 29 through 37 will be controlled purchasing engines certified to meet EPA federal emissions standards in NSPS Subpart IIII, by combusting clean fuel, and maintaining good combustion practices at all times the units are in operation;

(b) Particulate emissions from EU IDs 29 through 37 shall not exceed 0.25 g/kW-hr[10];

(c) For EU IDs 29 through 37, initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

[10] Particulate emissions of 0.25 g/kW-hr is equivalent to the EPA Nonroad Tier 2 standard for EUs 29 – 24 and Table 4 to NSPS Subpart IIII for EUs 35 – 37, both with a 1.25 not to exceed factor of safety.

7.4 VOC

Possible VOC emission control technologies for the limited use engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 Large (>500 hp) and 17.210 Small (≤500 hp), Fuel Oil Burning Internal Combustion Engines. The search results for the large and small diesel engines are summarized in Tables 7-19 and 7-20, respectively.

Table 7-19. VOC Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Oxidation Catalyst	2	0.21 – 0.24
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	47	0.020 – 6.4
Limited Operation	2	0.12 – 0.7
No Control Specified	5	0.20 – 0.79

Table 7-20. VOC Control for Small Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Federal Emission Standards, Clean Fuel, Good Combustion Practices, and Limited Use	38	0.07 – 7.5
No Control Specified	7	0.15 – 1.53

Step 1 – Identification of VOC Control Technologies for Black Start and Emergency Diesel Engines

From research, the Department identified the following technologies as available for VOC control of limited use engines rated at 500 hp or greater:

(a) **Oxidation Catalyst**
See control description in Section 3.1.

(b) **Good Combustion Practices and Clean Fuel**
See control description in Section 3.1

(c) **Federal Emission Standards**
See control description in Section 3.1. The limited use diesel engines will have to comply with the federal emissions standards in NSPS Subpart IIII.

(d) **Limited Operation**
See control description in Section 3.1 The Department considers limited operation a technically feasible control technology for the limited use diesel engines.

Step 2 – Elimination of Technically Infeasible VOC Control Options for Limited Use Diesel Engines

All control technologies listed above are technically feasible.

Step 3 – Ranking of Remaining VOC Control Options for Limited Use Diesel Engines

The following control technologies have been identified and ranked for control of VOC from the emergency engines:

(a) Limited Use (94% Control)

(b) Oxidation Catalyst (90% Control)

(c) Good Combustion Practices (Less than 90% Control)

(d) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls

Limited use and Catalytic oxidation are the most effective controls at reducing VOC emissions from EU IDs 29 through 37 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review

A review of similar units in the RBLC indicates that catalytic oxidation add-on control technology is not practical for the smaller 252 hp limited use engines EU IDs 35 through 37 that have minimal emissions. Based on the small potential to emit associated with these units (0.49 tpy of combined CO and VOC emissions per engine), catalytic oxidation is not a cost-effective control technology for the smaller limited use engines. However, the Department did find instances of oxidation catalysts used on larger engines in the RBLC, and EU IDs 29 and 30 have potential combined CO and VOC emissions of 1.58 tpy for each engine and EU IDs 31 through 34 have potential combined CO and VOC emissions of 3.95 tpy for each engine. Therefore, catalytic oxidation is advanced for the larger limited use engines EU IDs 29 through 34.

Applicant Proposal

Donlin provided combined CO and VOC economic analyses using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (catalytic oxidation) on the limited use diesel engines to demonstrate that this control is not economically feasible for these units. For their economic analyses, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2021 CEPCI of 772.5, the default life expectancy of 20 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 500 hours of operation per year for the black start and emergency diesel generators. A summary of Donlin's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-21 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-22. Note that all these analyses are per engine for combined CO and VOC emissions reductions. The remaining limited use diesel engines EU IDs 35 through 37 all have less than 1.0 tpy each of combined CO and VOC emissions and were not analyzed.

Table 7-21: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.02	1.57	$246,464	$40,161	$25,536
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 7-22: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.04	3.93	$406,923	$64,493	$16,403
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the limited use diesel engines based on the excessive cost per ton of pollutants removed per year.

Donlin proposes the following as BACT for VOC emissions from the limited use diesel engines:

(a) VOC emissions from EU IDs 29 through 37 will be controlled purchasing engines certified to meet EPA federal emissions standards in NSPS Subpart IIII, by combusting clean fuel, and maintaining good combustion practices at all times the units are in operation;

(b) NOx + NMHC emissions from EU IDs 29 through 34 will not exceed 8.0 g/kW-hr (EPA Nonroad Tier 2 emissions standard plus 25% not to exceed factor of safety); and

(c) NOx + NMHC emissions from EU IDs 35 through 37 will not exceed 5.0 g/kW-hr (Table 4 to NSPS Subpart IIII plus 25% not to exceed factor of safety).

Department Evaluation of BACT for VOC Emissions from Limited Use Diesel Engines

The Department revised the cost analyses changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams from the combustion of ULSD as opposed to coal. The Department kept the other assumptions unchanged including the 99 percent control efficiency, the interest rate of 8%, and assumed 500 hours per year of emergency operation. A summary of the Department's analyses are as follows: Black Start Generators EU IDs 29 and 30 are shown in Table 7-23 and Camp Site Emergency Generator EU IDs 31 through 34 are shown in Table 7-24. Note that all these analyses are per engine for combined CO and VOC emissions reductions and assumes VOC emissions to be 5% of the total NOx + NMHC emissions. The remaining limited use diesel engines EU IDs 35 through 37 all have less than 1.0 tpy each of combined CO and VOC emissions and were not analyzed.

Table 7-23: Department Analysis for Technically Feasible VOC Controls (EU IDs 29 & 30)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.02	1.57	$246,464	$38,149	$24,257
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 7-24: Department Analysis for Technically Feasible VOC Controls (EU IDs 31 – 34)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.04	3.93	$406,923	$61,173	$15,559
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EU IDs 29 through 34 (or the smaller EU IDs 35 through 37) with economic analyses showing costs in the range of $15,559 to $24,257 per ton of pollutants removed.

Step 5 – Selection of VOC BACT for Limited Use Diesel Engines

The Department's finding is that BACT for VOC emissions from the limited use diesel engines is as follows:

(a) VOC emissions from EU IDs 29 through 37 will be controlled purchasing engines certified to meet EPA federal emissions standards in NSPS Subpart IIII and maintaining good combustion practices at all times the units are in operation;

(b) NOx + NMHC emissions from EU IDs 29 through 34 will not exceed 8.0. g/kW-hr (EPA Nonroad Tier 2 emissions standard for NOx + NMHC plus 25% not to exceed factor of safety);

(c) NOx + NMHC emissions from EU IDs 35 through 37 will not exceed 5.0 g/kW-hr (Table 4 to NSPS Subpart IIII emissions standard for NOx + NMHC plus 25% not to exceed factor of safety); and

(d) For EU IDs 29 through 37, initial compliance with the proposed NOx + NMHC emission limits will be demonstrated by conducting a performance test to obtain an emission rate, or supplying the Department with a vendor verification that the EUs will comply with the BACT limits.

7.5 GHG

Possible GHG emission control technologies for limited use engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110 Large (>500 hp) and 17.210 Small (≤500 hp), Fuel Oil Burning Internal Combustion Engines. The search results for the large and small diesel engines are summarized in Tables 7-25 and 7-26, respectively.

Table 7-25. GHG Control for Large Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (tpy)
Good Combustion Practices and Clean Fuel	52	37 – 1,299,630
No Control Specified	14	14 – 7,194

Table 7-26. GHG Control for Small Oil-Fired Engines

Control Technology	Number of Determinations	Emission Limits (tpy)
Good Combustion Practices and Clean Fuel	46	7 – 3,083
No Control Specified	12	5 – 516

Step 1 – Identification of GHG Control Technologies for Limited Use Diesel Engines

From research, the Department identified the following technologies as available for GHG control of the limited use diesel engines:

(a) CCS
See control description in Section 3.5.

(b) GCPs and Clean Fuel
See control description in Sections 3.1 and 3.5.

Step 2 – Elimination of Technically Infeasible GHG Control Options for Limited Use Diesel Engines
CCS is technically infeasible for the reasons stated in Section 3.5.

Step 3 – Ranking of Remaining GHG Control Options for Limited Use Diesel Engines
Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Good combustion practices and clean fuel will reduce GHG emissions from EU IDs 29 through 37 while having minimal energy and environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices are the principal control method for limiting GHG emissions from diesel engines.

Applicant Proposal
Donlin proposed to use good combustion practices for EU IDs 29 through 37 as BACT for reducing GHG emissions from the limited use diesel engines. The proposed BACT GHG emission limit will be 3,007 tons per year of GHG emissions combined for EU IDs 29 through 37.

Step 5 – Selection of GHG BACT for Large Engines
The Department's finding is that BACT for GHG emissions from the limited use diesel engines is as follows:

(a) GHG emissions from EU IDs 29 through 37 shall be minimized by maintaining good combustion practices at all times the units are in operation; and

(b) GHG emissions from EU IDs 29 through 37 shall not exceed 3,007 tpy combined.

8.0 Small Diesel Engines
Electric power for the airport will be generated from two diesel-fired reciprocating-engines (EU IDs 13 and 14). Each engine will be rated at 200 kW. The airport generators will emit CO, NOx, SO_2, particulates, VOC, and GHG. The following sections provide a BACT review for each of these pollutants (except SO_2) for each fuel type.

8.1 CO
Possible CO emission control technologies for small diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.21, Small Internal Combustion Engines (<500 hp), subcategory Fuel Oil. The search results for small diesel engines are summarized in Table 8-1.

Table 8-1. CO Control for Small Diesel Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Federal Emission Standards, Clean Fuel, & Good Combustion Practices	70	0.67 – 11
Limited Use	5	1.6 - 3.5
No Control Specified	11	0.7 - 5

Step 1 – Identification of CO Control Technologies for Small Diesel Engines
From research, the Department identified the following technologies as available for CO control of engines rated at 500 hp or less:

(a) Oxidation Catalyst
See control description in Section 3.1. The Department did not identify add-on oxidation catalysts used in any small oil-fired engines in the RBLC.

(b) Good Combustion Practices
See control description in Section 3.1

(c) Federal Emission Standards
See control description in Section 3.1. The small diesel engines are required to comply with the federal emissions standards in NSPS Subpart IIII.

(d) Limited Operation
See control description in Section 3.1 The Department considers limited operation a technically infeasible control technology for the diesel engines that provide power to the airport and cannot have their hours of operation meaningfully limited.

Step 2 – Elimination of Technically Infeasible CO Control Options for Small Diesel Engines
As explained in Step 1, limited operation is not a feasible technology to control CO emissions from the airport generator engines.

Step 3 – Ranking of Remaining CO Control Options for Small Diesel Engines
The following control technologies have been identified and ranked for control of CO from the small engines:

(a) Oxidation Catalyst (90% Control)

(b) Good Combustion Practices (Less than 90% Control)

(c) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
Catalytic oxidation will reduce CO emissions from EU IDs 13 and 14 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and federal emissions standards are the principal CO control technologies for small diesel engines.

Applicant Proposal
Donlin provided a combined CO and VOC economic analysis using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (catalytic oxidation) on the small diesel engines to demonstrate that this control is not economically feasible for these units. For their economic analysis, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2021 CEPCI of 772.5, the default life expectancy of 20 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 8,760 hours of operation per year for the small diesel generators. A summary of Donlin's analysis is shown below in Table 8-2. Note that all these analyses are per engine for combined CO and VOC emissions reductions.

Table 8-2: Donlin Analysis for Technically Feasible CO Controls (EU IDs 13 & 14)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.01	8.85	$152,307	$101,803	$11,509
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the small diesel engines based on the excessive cost per ton of CO removed per year.

Donlin proposes the following as BACT for CO emissions from the small diesel engines:

(a) CO emissions from EU IDs 13 and 14 will be controlled by maintaining good combustion practices at all times the units are in operation and installing engines certified to meet EPA Tier 4 emissions standards; and

(b) CO emissions from EU IDs 13 and 14 shall not exceed 4.38 g/kW-hr.

Department Evaluation of BACT for CO Emissions from Small Diesel Engines

The Department revised the cost analysis changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams from the combustion of ULSD as opposed to coal. The Department kept the other assumptions unchanged including the 99 percent control efficiency and the interest rate of 8% and assumed 8,760 hours per year of operation (unlimited). A summary of the Department's analysis is shown below in Table 8-3. Note that all these analyses are per engine for combined CO and VOC emissions reductions.

Table 8-3: Department Analysis for Technically Feasible CO Controls (EU IDs 13 & 14)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.01	8.85	$152,307	$100,559	$11,368
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EU IDs 13 and 14 with an economic analysis showing costs of $11,368 per ton of pollutants removed.

Step 5 – Selection of CO BACT for Small Diesel-Fired Engines

The Department's finding is that BACT for CO emissions from the small diesel engines is as follows:

(a) CO emissions from the operation of the diesel engines EU IDs 13 and 14 shall be controlled by purchasing EPA Tier 4 Final engines and maintaining good combustion practices at all times the units are in operation;

(b) CO emissions from the operation of the diesel engines EU IDs 13 and 14 will not exceed 4.38 g/kW-hr @ 15% O_2 (EPA Tier 4 Final, includes 25% not to exceed factor of safety); and

(c) Initial compliance with the proposed CO emission limit will be demonstrated by purchasing engines certified to meet the EPA Tier 4 Final emissions standards or by conducting a performance test to obtain an emission rate.

8.2 NOx

Possible NOx emission control technologies for small diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.21, Small Internal Combustion Engines (<500 hp), subcategory Fuel Oil. The search results for small diesel engines are summarized in Table 8-4.

Table 8-4. NOx Control for Small Diesel Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Federal Emission Standards, Clean Fuel, Limited Use, & Good Combustion Practices	64	0.4 - 26
No Control Specified	8	3.82 - 18.85

Step 1 – Identification of NOx Control Technologies for Small Diesel Engines

From research, the Department identified the following technologies as available for NOx control of engines rated at 500 hp or less:

(a) **Selective Catalytic Reduction (SCR)**
See control description in Section 3.2. The Department did not identify add-on SCR control systems used in any small oil-fired engines in the RBLC.

(b) Good Combustion Practices
See control description in Section 3.1.

(c) Federal Emission Standards
See control description in Section 3.1. The small diesel engines are required to comply with the federal emissions standards in NSPS Subpart IIII.

(d) Limited Operation
See control description in Section 3.1 The Department considers limited operation a technically infeasible control technology for the diesel engines that provide power to the airport and cannot have their hours of operation meaningfully limited.

Step 2 – Elimination of Technically Infeasible NOx Control Options for Small Diesel Engines
As explained in Step 1, limited operation is not a feasible technology to control NOx emissions from the airport generator engines.

Step 3 – Ranking of Remaining NOx Control Options for Small Diesel Engines
The following control technologies have been identified and ranked for control of NOx from the small diesel engines:

(a) SCR	(90% Control)
(b) Good Combustion Practices	(Less than 90% Control)
(c) Federal Emission Standards	(Baseline)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective control at reducing NOx emissions from small diesel engines while having minimal energy and environmental impacts. Environmental impacts include the SCR adding exhaust back pressure that decreases the engine's efficiency and requires additional fuel consumption; the SCR catalyst does need to be replaced and recycled as necessary, and the SCR will emit ammonia from the ammonia slip of the system.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and federal emissions standards are the principal NOx control technology for small diesel engines. Additionally, the RBLC review indicates add-on control technology (beyond EPA Tier 4 emissions controls) is not practical for small engines. Based on the small potential to emit associated with these units (1.2 tpy) and the SCR cost analyses for the higher emitting diesel engine EU IDs 29 through 34 in Tables 7-11 and 7-12, SCR (beyond those associated with EPA Tier 4 emissions controls) is not a cost-effective control technology for the small diesel engines.

Applicant Proposal
Donlin proposed to use good combustion practices and install EPA certified Tier 4 engines as BACT for NOx. For EU IDs 13 and 14 the BACT NOx emission rate will be 0.50 g/kW-hr.

Step 5 – Selection of NOx BACT for Small Diesel-Fired Engines
The Department's finding is that BACT for NOx emissions from the small diesel engines is as follows:

(a) NOx emissions from the operation of the diesel engines EU IDs 13 and 14 shall be controlled by purchasing EPA Tier 4 Final engines and maintaining good combustion practices at all times the units are in operation;

(b) NOx emissions from the operation of the diesel engines EU IDs 13 and 14 will not exceed 0.60 g/kW-hr @ 15% O_2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety); and

(c) Initial compliance with the proposed NOx emission limit will be demonstrated by purchasing engines certified to meet the EPA Tier 4 Final emissions standards or by conducting a performance test to obtain an emission rate.

8.3 Particulates

Possible particulate emission control technologies for small diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.21, Small Internal Combustion Engines (<500 hp), subcategory Fuel Oil. The search results for small diesel engines are summarized in Table 8-5.

Table 8-5. Particulate Control for Small Diesel Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Diesel Particulate Filter	3	0.66 (lb/hr) 0.54 (g/kW-hr)
Clean Fuel, Good Combustion Practices, Limited Operation, and Federal Emission Standards	116	0.02 - 0.5 (g/kW-hr)
No Control Specified	13	0.2 – 1.34 (g/kW-hr)

Step 1 – Identification of Particulate Control Technologies for Small Diesel Engines

From research, the Department identified the following technologies as available for particulate control of engines rated at 500 hp or less:

(a) Diesel Particulate Filter (DPF)
See control description in Section 3.3.

(b) Good Combustion Practices
See control description in Section 3.1.

(c) Limited Use
See control description in Section 3.1. The Department considers limited operation a technically infeasible control technology for the diesel engines that provide power to the airport and cannot have their hours of operation meaningfully limited.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Small Diesel Engines

As explained in Step 1, limited operation is not a feasible technology to control particulate emissions from the airport generator engines.

Step 3 – Ranking of Remaining Particulate Control Options for Small Diesel Engines

The following control technologies have been identified and ranked for control of particulate emissions from the diesel engines.

(a) Diesel Particulate Filters (85% Control)

(b) Good Combustion Practices (Less than 40% Control)

(c) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
Diesel particulate filters are the most effective control at reducing particulate emissions from small diesel engines while having minimal energy and environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices, clean fuels, and federal emissions standards are the principal particulate control technology for small diesel engines. Additionally, the RBLC review indicates add-on control technology (beyond EPA Tier 4 emissions controls) is not practical for small engines. Based on the small potential to emit associated with these units (less than 0.1 tpy), and the SCR cost analyses for diesel engine EU IDs 29 through 34 in Tables 7-17 and 7-18, diesel particulate filters (beyond those associated with EPA Tier 4 emissions controls) are not a cost-effective control technology for the small diesel engines.

Applicant Proposal
Donlin proposed to use clean fuel, good combustion practices, and install EPA certified Tier 4 engines as BACT for particulates. For EU IDs 13 and 14 the BACT particulate emission rate will be 0.03 g/kW-hr.

Step 5 – Selection of Particulate BACT for Small Diesel-Fired Engines
The Department's finding is that BACT for particulate emissions from the small diesel engines is as follows:

(a) Particulate emissions from the operation of the diesel engines EU IDs 13 and 14 shall be controlled by purchasing EPA Tier 4 Final engines, maintaining good combustion practices, and combusting ULSD at all times the units are in operation;

(b) Particulate emissions from the operation of the diesel engines EU IDs 13 and 14 will not exceed 0.03 g/kW-hr @ 15% O_2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety); and

(c) Initial compliance with the proposed particulate emission limit will be demonstrated by purchasing engines certified to meet the EPA Tier 4 Final emissions standards or by conducting a performance test to obtain an emission rate.

8.4 VOC
Possible VOC emission control technologies for small diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.21, Small Internal Combustion Engines (<500 hp), subcategory Fuel Oil. The search results for small diesel engines are summarized in Table 8-6.

Table 8-6. VOC Control for Small Diesel Engines

Control Technology	Number of Determinations	Emission Limits (g/kW-hr)
Federal Emission Standards, Clean Fuel, Good Combustion Practices, and Limited Use	38	0.07 – 7.5
No Control Specified	7	0.15 – 1.53

Step 1 – Identification of VOC Control Technologies for Small Diesel Engines
From research, the Department identified the following technologies as available for VOC control of engines rated at 500 hp or less:

(a) Oxidation Catalyst
See control description in Section 3.1.

(b) Good Combustion Practices and Clean Fuel
See control description in Section 3.1

(c) Federal Emission Standards
See control description in Section 3.1. The limited use diesel engines will have to comply with the federal emissions standards in NSPS Subpart IIII.

(d) Limited Operation
See control description in Section 3.1 The Department considers limited operation a technically infeasible control technology for the diesel engines that provide power to the airport and cannot have their hours of operation meaningfully limited.

Step 2 – Elimination of Technically Infeasible VOC Control Options for Small Diesel Engines
As explained in Step 1, limited operation is not a feasible technology to control VOC emissions from the airport generator engines.

Step 3 – Ranking of Remaining VOC Control Options for Small Diesel Engines
The following control technologies have been identified and ranked for control of VOC from the emergency engines:

(a) Oxidation Catalyst (90% Control)

(b) Good Combustion Practices (Less than 90% Control)

(c) Federal Emission Standards (Baseline)

Step 4 – Evaluate the Most Effective Controls
Catalytic oxidation will reduce VOC emissions from EU IDs 13 and 14 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Engine efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices, clean fuel, and federal emissions standards are the principal VOC control technologies for small diesel engines.

Applicant Proposal
Donlin provided a combined CO and VOC economic analysis using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (catalytic oxidation) on the small diesel engines to demonstrate that this control is not economically feasible for these units. For their economic analyses, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2021 CEPCI of 772.5, the default life expectancy of 20 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 8,760 hours of operation per year for each small diesel generator. A summary of Donlin's analysis is shown below in Table 8-7. Note that all these analyses are per engine for combined CO and VOC emissions reductions.

Table 8-7: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 13 & 14)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.01	8.85	$152,307	$101,803	$11,509
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the small diesel engines based on the excessive cost per ton of CO removed per year.

Donlin proposes the following as BACT for VOC emissions from the small diesel engines:

(a) VOC emissions from EU IDs 13 and 14 will be controlled by maintaining good combustion practices at all times the units are in operation and installing engines certified to meet EPA Tier 4 emissions standards; and

(b) VOC emissions from EU IDs 13 and 14 shall not exceed 0.24 g/kW-hr.

Department Evaluation of BACT for VOC Emissions from Small Diesel Engines

The Department revised the cost analysis changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams from the combustion of ULSD as opposed to coal. The Department kept the other assumptions unchanged including the 99 percent control efficiency and the interest rate of 8% and assumed 8,760 hours per year of operation fir each engine (unlimited). A summary of the Department's analysis is shown below in Table 8-8. Note that all these analyses are per engine for combined CO and VOC emissions reductions.

Table 8-8: Department Analysis for Technically Feasible VOC Controls (EU IDs 13 & 14)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.01	8.85	$152,307	$100,559	$11,368
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EU IDs 13 and 14 with an economic analysis showing costs of $11,368 per ton of pollutants removed.

Step 5 – Selection of VOC BACT for Small Diesel-Fired Engines

The Department's finding is that BACT for VOC emissions from the small diesel engines is as follows:

(a) VOC emissions from the operation of the diesel engines EU IDs 13 and 14 shall be controlled by purchasing EPA Tier 4 Final engines and maintaining good combustion practices at all times the units are in operation;

(b) VOC emissions from the operation of the diesel engines EU IDs 13 and 14 will not exceed 0.29 g/kW-hr @ 15% O_2 (EPA Tier 4 Final, includes 50% not to exceed factor of safety); and

(c) Initial compliance with the proposed VOC emission limit will be demonstrated by purchasing engines certified to meet the EPA Tier 4 Final emissions standards or by conducting a performance test to obtain an emission rate.

8.5 GHG

Possible GHG emission control technologies for small diesel engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 17.21, Small Internal Combustion Engines (<500 hp), subcategory Fuel Oil. The search results for small diesel engines are summarized in Table 8-9.

Table 8-9. GHG Control for Small Diesel Engines

Control Technology	Number of Determinations	Emission Limits (tpy)
Good Combustion Practices and Clean Fuel	46	7 – 3,083
No Control Specified	12	5 – 516

Step 1 – Identification of GHG Control Technologies for Small Diesel Engines

From research, the Department identified the following technologies as available for GHG control of engines rated at 500 hp or less:

(a) CCS
See control description in Section 3.5.

(b) GCPs and Clean Fuel
See control description in Sections 3.1 and 3.5.

Step 2 – Elimination of Technically Infeasible GHG Control Options for Small Diesel Engines

CCS is technically infeasible for the reasons stated in Section 3.5.

Step 3 – Ranking of Remaining GHG Control Options for Small Diesel Engines

Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

Good combustion practices and clean fuel will reduce GHG emissions from EU IDs 13 and 14 while having minimal energy and environmental impacts.

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices are the principal control method for GHG emissions from small diesel engines.

Applicant Proposal

Donlin proposed to use good combustion practices for EU IDs 13 and 14 as BACT for reducing GHG emissions from small diesel engines. The BACT GHG emission limit will be 2,691 tons per year of GHG emissions combined for EU IDs 13 and 14.

Step 5 – Selection of GHG BACT for Small Engines

The Department's finding is that BACT for GHG emissions from the small diesel engines is as follows:

(a) GHG emissions from EU IDs 13 and 14 shall be minimized by maintaining good combustion practices at all times the units are in operation; and

(b) GHG emissions from EU IDs 13 and 14 shall not exceed 2,691 tpy combined.

9.0 Carbon Regeneration Kiln

The carbon regeneration kiln (EU ID 88) heats (with electricity) used activated carbon to reactivate the carbon for reuse in the process. The carbon regeneration kiln has a design process rate of 1.65 tons per hour of carbon and will emit CO, NOx, particulates, and VOC. The following sections provide a BACT review for each of these pollutants.

The RBLC currently does not have determinations for carbon regeneration kilns other than the previous entry for Donlin Gold Mine's Construction Permit AQ0934CPT01. Table 9-1 below lists existing gold mining operations in Alaska with minor or Title V permits with carbon regeneration emission sources.

Table 9-1. Existing Sources with a Carbon Regeneration Kiln

Facility	Control Technology for Carbon Regeneration Kiln
Fort Knox Mine	No emission controls are listed in their Title V permit
Pogo Mine	Wet scrubber for particulate emissions control

9.1 CO

Possible CO emission control technologies for carbon regeneration kilns were determined based on research for similar units. Alaska currently has two mines using similar units.

Step 1 – Identification of CO Control Technologies for the Carbon Regeneration Kiln
From research, the Department identified the following technologies as available for CO control of carbon regeneration kilns:

(a) Oxidation Catalyst
See control description in Section 3.1.

(b) Good Combustion Practices
See control description in Section 3.1

Step 2 – Elimination of Technically Infeasible CO Control Options for the Carbon Regeneration Kiln
Both control technologies listed above are technically feasible.

Step 3 – Ranking of Remaining CO Control Options for the Carbon Regeneration Kiln
The following control technologies have been identified and ranked for control of CO from the emergency engines:

(a) Oxidation Catalyst (90% Control)

(b) Good Combustion Practices (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
Catalytic oxidation will reduce CO emissions from EU ID 88 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary.

Facility Review
A review of similar sources in Alaska indicates add-on control technology to treat CO emissions are not currently in use on carbon regeneration kilns.

Applicant Proposal
Donlin provided a combined CO and VOC economic analysis using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technology (catalytic oxidation) on the carbon regeneration kiln to demonstrate that this control is not economically feasible for the EU. For their economic analysis, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2022 CEPCI of 785.9, the default life expectancy of 20 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 8,760 hours of operation per year for the kiln. A summary of Donlin's combined CO and VOC economic analysis is shown below in Table 9-2.

Table 9-2: Donlin Analysis for Technically Feasible CO Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	5.72	$321,504	$213,810	$37,355
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the carbon regeneration kiln based on the excessive cost per ton of CO removed per year.

Donlin proposes the following as BACT for CO emissions from the carbon regeneration kiln:

(a) CO emissions from EU ID 88 will be controlled by maintaining good operating practices at all times the unit is in operation; and

(b) CO emissions from EU ID 88 shall not exceed 0.88 lb/hr.

Department Evaluation of BACT for CO Emissions from Carbon Regeneration Kiln
The Department revised the cost analysis changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams from the carbon regeneration kiln as opposed to coal. The Department kept the other assumptions unchanged including the 99 percent control efficiency and the interest rate of 8% and assumed 8,760 hours per year of operation (unlimited). A summary of the Department's combined CO and VOC economic analysis is shown below in Table 9-3.

Table 9-3: Department Analysis for Technically Feasible CO Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	5.72	$321,504	$211,186	$36,896
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst as BACT for EU ID 88 with an economic analysis showing costs of $13,896 per ton of pollutants removed.

Step 5 – Selection of CO BACT for Carbon Regeneration Kiln
The Department's finding is that BACT for CO emissions from the carbon regeneration kiln is as follows:

(a) CO emissions from EU ID 88 shall be controlled by maintaining good operating practices at all times the unit is in operation;

(b) CO emissions from EU ID 88 shall not exceed 0.88 lb/hr; and

(c) Compliance with the proposed emission limit will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

9.2 NOx

Possible NOx emission control technologies for carbon regeneration kilns were determined based on research for similar units. Alaska currently has two mines using similar units.

Step 1 – Identification of NOx Control Technologies for the Carbon Regeneration Kiln
From research, the Department identified the following technologies as available for NOx control of carbon regeneration kilns:

(a) **Selective Catalytic Reduction (SCR)**
See control description in Section 3.2

(b) Good Operating Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible NOx Control Options for the Carbon Regeneration Kiln
Both control technologies listed above are technically feasible for control of NOx emissions from the carbon regeneration kiln.

Step 3 – Ranking of Remaining NOx Control Options for the Carbon Regeneration Kiln
The following control technologies have been identified and ranked for control of NOx from the carbon regeneration kilns:

(a) SCR (90% Control)

(b) Good Operating Practices (Less than 90% Control)

Step 4 – Evaluate the Most Effective Controls
In theory, SCR would be the most effective means of controlling NOx emissions from the carbon regeneration kiln. However, there are no similar units to review in the RBLC which indicates that add-on control technology is not practical for carbon regeneration kilns. Based on the small potential to emit associated with this unit of less than 0.1 tpy and the previous economic analyses conducted for SCR control systems in Section 6.2 and 7.2, this is not a cost-effective control technology for carbon regeneration kilns.

Applicant Proposal
Donlin proposed to use good operating practices as NOx BACT. The resulting NOx BACT emission rate is 0.02 lb/hr for EU ID 88.

Step 5 – Selection of NOx BACT for Carbon Regeneration Kiln
The Department's finding is that BACT for NOx emissions from the carbon regeneration kiln is as follows:

(a) NOx emissions from the operation of the carbon regeneration kiln EU ID 88 shall be controlled by maintaining good operating practices at all times the unit is in operation;

(b) NOx emissions from the operation of the carbon regeneration kiln EU ID 88 will not exceed 0.02 lb/hr; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

9.3 Particulates

Possible particulate emissions control technologies for carbon regeneration kilns were determined based on research for similar units. Alaska currently has two mines using similar units.

Step 1 – Identification of PM Control Technologies for the Carbon Regeneration Kiln
From research, the Department identified the following technologies as available for particulate control of carbon regeneration kilns:

(a) Dust Collector
See control description in Section 4.1.

(b) ESP
See control description in Section 4.1.

(c) Good Operating Practices
See control description in Section 3.1.

(d) Wet Scrubber
See control description in Section 4.1

(e) Wet Off-Gas Cooler
Wet Off-Gas Coolers, like wet scrubbers, use a solution to remove particulate matter from exhaust streams. The mechanism for particulate collection is impaction and interception by water droplets. The wet off-gas cooler will control particulate emissions and is necessary to reduce the exhaust gas temperature prior to entering the carbon bed for mercury control.

Step 2 – Elimination of Technically Infeasible PM Control Options for the Carbon Regeneration Kiln
All listed control methods for EU ID 88 are technically feasible.

Step 3 – Ranking of Remaining PM Control Options for the Carbon Regeneration Kiln
The following control technologies have been identified and ranked for control of particulates from the carbon regeneration kiln:

(a) Dust Collector (>99% Control)

(b) ESP (>99% Control)

(c) Wet Scrubber (>97% Control)

(d) Wet Off-Gas Cooler (50% Control)

(e) Good Operating Practices (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls
The most effective control for particulate emissions from EU ID 88 is to use a dust collector or ESP. These control methods will have minimal impacts on the environment.

Applicant Proposal
Donlin provided particulate matter economic analyses using EPA's Air Pollution Control Cost Manual[7] for the installation of the most effective control technologies (dust collectors, dry ESPs, and wet scrubbers) on the carbon regeneration kiln to demonstrate that these controls are not economically feasible for EU ID 88. For their economic analysis of dry ESPs, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Both figures are based on the EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[11]. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the kiln. A summary of Donlin's economic analysis for dry ESP is shown below in Table 9-4.

Table 9-4: Donlin Analysis for Technically Feasible PM Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.01	1.92	$343,698	$147,538	$76,979
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

[11] https://www3.epa.gov/ttn/catc/dir1/fdespwpi.pdf

For their economic analysis of wet scrubbers, Donlin used an emission reduction efficiency of 98.45 percent and a life expectancy of 15 years for the control system. Respectively, both figures are based on p. 2-43 and p. 2-51 of EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2 (EPA 2002)[12]. In their economic analysis, Donlin assumed the control unit as a low-energy wet scrubber with a saturated air flow rate range of 1,000 cfm to 90,000 cfm. Donlin also assumed the material used for the wet scrubber would be alloy C-275. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the kiln. A summary of Donlin's economic analysis for wet scrubbers is shown below in Table 9-5.

Table 9-5: Donlin Analysis for Technically Feasible PM Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.03	1.90	$168,180	$215,183	$113,413
Capital Recovery Factor = 0.1168 (8% for a 15-year life cycle)					

For their economic analysis of dust collectors, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Respectively, both figures are based on p. 1-50 and p. 1-55 of EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 1 (EPA 1998)[13]. Donlin assumed the control unit as a pulse-jet baghouse. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the kiln. A summary of Donlin's economic analysis for dust collectors is shown below in Table 9-6.

Table 9-6: Donlin Analysis for Technically Feasible PM Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.01	1.92	$79,318	$197,058	$102,816
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analyses indicate that the level of particulate emissions reduction does not justify the use of an ESP, a wet scrubber, or a dust collector on the carbon regeneration kiln based on the excessive cost per ton of particulate emissions removed per year.

Donlin proposes the following as BACT for particulate emissions from the carbon regeneration kiln:

(a) Particulate emissions from EU ID 88 shall be controlled by always operating a wet off-gas cooler (EU ID 89) when the unit is in operation;

(b) Particulate emissions from EU ID 88 shall not exceed 0.44 lb/hr.

Department Evaluation of BACT for PM Emissions from Carbon Regeneration Kiln

The Department revised the cost analysis for dry ESPs and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department changed the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[11]. The Department also adjusted the cost per unit of flowrate (2002) to the lowest value, $10/scfm,

[12] https://www.epa.gov/sites/default/files/2020-07/documents/cs6ch2.pdf
[13] https://www.epa.gov/sites/default/files/2020-07/documents/cs6ch1.pdf

which is also based on EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003) [11]. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the kiln. A summary of the Department's PM economic analysis is shown below in Table 9-7.

Table 9-7: Department Analysis for Technically Feasible PM Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.002	1.93	$104,151	$110,996	$57,652
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for wet scrubbers and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department also adjusted the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2, p. 2-43 (EPA 2002)[12]. The Department changed the assumptions used to determine the costs of the system. Instead of assuming the material used for the wet scrubber would be alloy C-276, the Department assumed the material would be carbon steel, a less costly alternative. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the kiln. A summary of the Department's PM economic analysis is shown below in Table 9-8.

Table 9-8: Department Analysis for Technically Feasible PM Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.002	1.93	$168,180	$211,289	$109,745
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for dust collectors and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department also changed the control efficiency to 99.9 percent, the maximum control efficiency listed in the EPA's Air Pollution Control Cost Manual, Sec. 6, Ch.1, p. 1-4 (EPA 1998)[13]. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the kiln. A summary of the Department's PM economic analysis is shown below in Table 9-9.

Table 9-9: Department Analysis for Technically Feasible PM Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.002	1.93	$79,905	$196,626	$102,129
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analyses indicate that the level of particulate emissions reduction does not justify the use of an ESP, a wet scrubber, or a dust collector as BACT for EU ID 88. The economic analyses show the costs per ton of particulate emissions removed per year are excessively high.

Step 5 – Selection of Particulate BACT for Carbon Regeneration Kiln
The Department's finding is that BACT for particulate emissions from the carbon regeneration kiln is as follows:

(a) Particulate emissions from EU ID 88 shall be controlled by operating a wet off-gas cooler (EU ID 89) at all times the unit is in operation;

(b) Particulate emissions from EU ID 88 shall not exceed 0.44 lb/hr; and

(c) Compliance with the proposed emission limit will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

9.4 VOC

Possible VOC emission control technologies for carbon regeneration kilns were determined based on research for similar units. Alaska currently has two mines using similar units.

Step 1 – Identification of VOC Control Technologies for the Carbon Regeneration Kiln
From research, the Department identified the following technologies as available for VOC control of carbon regeneration kilns:

(a) **Thermal Oxidation**
See control description in Section 5.1

(b) **Catalytic Oxidation**
See control description in Section 5.1

(c) Good Operating Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible VOC Control Options for the Carbon Regeneration Kiln
All control technologies listed above are technically feasible.

Step 3 – Ranking of Remaining VOC Control Options for the Carbon Regeneration Kiln
The following control technologies have been identified and ranked for control of VOC from the carbon regeneration kiln:

(a) Thermal Oxidizer	(95 – 95% Control)
(b) Oxidation Catalyst	(90% Control)
(c) Good Operating Practices	(<40% Control)

Step 4 – Evaluate the Most Effective Controls
The most effective control for VOC reduction would be to use a thermal oxidizer or an oxidation catalyst. However, the Department found no examples of these control technologies being used on carbon regeneration kilns.

Applicant Proposal
Donlin provided a combined CO and VOC economic analysis using EPA's Air Pollution Control Cost Manual[8] for the installation of catalytic oxidation on the carbon regeneration kiln to demonstrate that this control is not economically feasible for the EU. For their economic analysis, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2022 CEPCI of 785.9, the default life expectancy of 20 years for the control system, the Donlin Gold Project borrowing interest rate of 8.0 percent, and assumed 8,760 hours of operation per year for

the kiln. A summary of Donlin's combined CO and VOC economic analysis is shown below in Table 9-10.

Table 9-10: Donlin Analysis for Technically Feasible VOC Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	5.72	$321,504	$213,810	$37,355
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analysis indicates the level of combined CO and VOC reduction does not justify the use of catalytic oxidation on the carbon regeneration kiln based on the excessive cost per ton of pollutants removed per year.

Donlin proposed to use good operating practices as VOC BACT. The VOC BACT emission rate will be 0.44 lb/hr for EU ID 88.

Department Evaluation of BACT for VOC Emissions from Carbon Regeneration Kiln

The Department revised the catalytic oxidation cost analysis changing the estimated equipment life to 25 years to reflect an estimated longer life for oxidation catalyst control systems treating exhaust streams from the carbon regeneration kiln as opposed to coal. Additionally, the Department included additional revised cost analyses by changing the drop-down control feature in the EPA spreadsheet from Catalytic Oxidizer – Fixed Bed to both Recuperative Thermal Oxidizer and Regenerative Thermal Oxidizer. The rest of the remaining assumptions were left unchanged, including the estimated equipment life to 25 years, the 99 percent control efficiency, and the interest rate of 8 percent. A summary of the Department's analyses for the Carbon Regeneration Kiln (EU ID 88) are as follows: Catalytic Oxidizer – Fixed Bed in Table 9-11, Recuperative Thermal Oxidizer in Table 9-12, and Regenerative Thermal Oxidizer in Table 9-13.

Table 9-11: Department Analysis for Technically Feasible VOC Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.06	5.72	$321,504	$211,186	$36,896
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 9-12: Department Analysis for Technically Feasible VOC Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Recuperative Thermal Oxidizer	0.06	5.72	$266,371	$286,721	$50,093
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 9-13: Department Analysis for Technically Feasible VOC Controls (EU ID 88)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Regenerative Thermal Oxidizer	0.06	5.72	$894,076	$386,936	$67,601
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analysis indicates the level of combined CO and VOC reduction does not justify the use of an oxidation catalyst or thermal oxidizer as BACT for EU ID 88 with economic analyses showing costs in the range of $36,896 to $67,601 per ton of pollutants removed.

Step 5 – Selection of VOC BACT for Carbon Regeneration Kiln
The Department's finding is that BACT for VOC emissions from the carbon regeneration kiln is as follows:

(a) VOC emissions from EU ID 88 shall be controlled by maintaining good operating practices at all times the unit is in operation;

(b) VOC emissions from EU ID 88 shall not exceed 0.44 lb/hr; and

(c) Compliance with the proposed emission limit will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

10.0 Induction Smelting Furnace

An induction smelting furnace (EU ID 100) will be operated at DGP for gold refining. The induction smelting furnace will emit particulates. The following sections provide a particulate BACT review.

10.1 Particulates

Possible particulate emission control technologies for the induction smelting furnace were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process name containing "furnace" and the primary fuel as electricity. The search results are summarized in Table 10-1.

Table 10-1. Particulate Control for the Induction Smelting Furnace

Control Technology	Number of Determinations	Emission Limits (gr/dscf)
Dust Collector/Baghouse (includes sources with enclosures)	26	0.0008 - 0.0052

Step 1 – Identification of PM Control Technologies for the Induction Smelting Furnace
From research, the Department identified the following technologies as available for particulate control of an induction smelting furnace:

(a) Dust Collector
See control description in Section 4.1.

(b) ESP
See control description in Section 4.1.

(c) Wet Scrubber
See control description in Section 4.1.

(d) Enclosure
See control description in Section 4.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for the Induction Smelting Furnace
All control technologies listed above are technically feasible.

Step 3 – Ranking of Remaining Particulate Control Options for the Induction Smelting Furnace

The following control technologies have been identified and ranked for control of NOx from the induction smelting furnace:

(a) Dust Collector (>99% Control)

(b) Enclosure (>99% Control)

(c) ESP (>90% Control)

(d) Wet Scrubber (50% - 90% Control)

Step 4 – Evaluate the Most Effective Controls
A dust collector will reduce particulate emissions from EU ID 100 while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that dust collectors are the principal particulate control technologies installed on induction smelting furnaces.

Applicant Proposal
Donlin proposed to install a dust collector for EU ID 100 as BACT for reducing particulate emissions. The particulate BACT emission rate will be 0.005 gr/scf for EU ID 100.

Step 5 – Selection of Particulate BACT for Induction Smelting Furnace
The Department's finding is that BACT for particulate emissions for induction smelting furnace is as follows:

(a) Particulate emissions from EU ID 100 shall be controlled by operating and maintaining a dust collector at all times the unit is in operation;

(b) Particulate emissions from EU ID 100 shall not exceed 0.005 gr/scf averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

11.0 Pressure Oxidation Hot Cure

The oxidized ore concentrate slurry from the autoclaves will enter three POX hot cure tanks (85 - 87). The POX hot cure tanks will emit particulates. The following section provides a BACT review for particulates.

11.1 Particulates

Possible particulate emission control technologies for the pressure oxidation hot cure were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process names containing "cure" and "curing". The search results are summarized in Table 11-1.

Table 11-1. Particulate Control for the Pressure Oxidation Hot Cure

Facility No.	Type	Control Technology	Emission Limits
AK-0084[1]	Gold: Pressure Oxidation Hot Cure	Good Operating Practices	0.4 lb/hr
TX-0882	Steel: Casting	Wet material & partial enclosure	0.12 lb/ton
TX-0882	Steel: Curing Oven	GCPs & Clean Fuel	0.0075 lb/ton

Facility No.	Type	Control Technology	Emission Limits
MO-0089	Mineral Wool: Insulation Curing Oven	Stone wool filter, thermal oxidizer, & good operating practices	Not Listed
WV-0027	Insulation: Curing Oven	Wet scrubber	0.88 lb/ton
MI-0437	Fiberglass Insulation: Curing Process	Venturi scrubber	5.33 – 5.59 lb/ton 23.98 – 25.19 lb/hr

Table Notes

1. AK-0084 is an existing determination in the RBLC for Donlin Gold Project

Step 1 – Identification of Particulate Control Technologies for Pressure Oxidation Hot Cure

From research, the Department identified the following technologies as available for particulate control of ore hot curing:

(a) Dust Collector
See control description in Section 4.1.

(b) ESP
See control description in Section 4.1.

(c) Wet Scrubber
See control description in Section 4.1.

(d) Good Operating Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Pressure Oxidation Hot Cure

Dust collectors are technically infeasible because of the high moisture content of the hot cure exhaust.

Step 3 – Ranking of Remaining Particulate Control Options for Pressure Oxidation Hot Cure

The following control technologies have been identified and ranked for control of particulates from the hot cure:

(a) ESP (>99% Control)

(b) Wet Scrubber (>97% Control)

(c) Good Operating Practices (Less than 40% Control)

Step 4 – Evaluate the Most Effective Controls

These controls will have the most effective reductions on particulate matter emissions from the hot cure tanks while having minimal energy and environmental impacts. However, there is a waste effluent associated with wet scrubbers.

Applicant Proposal

Donlin provided economic analyses for controlling particulates using EPA's Air Pollution Control Cost Manual[7] for the installation of the most effective control technologies (wet ESPs and wet scrubbers) on the POX hot cure tanks to demonstrate that these controls are not economically feasible for EU IDs 85 through 87. For their economic analysis of wet ESP, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Respectively, both figures are based on EPA Fact Sheet, Wet Electrostatic

Precipitator (ESP) – Wire-Plate Type (EPA 2003)[14] and EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 3, p. 3-50 (EPA 1999)[15]. Donlin's economic analysis also used the Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year the POX hot cure tanks. A summary of Donlin's economic analysis for wet ESP is shown below in Table 11-2.

Table 11-2: Donlin Analysis for Technically Feasible PM Controls (EU IDs 85-87)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet ESP	0.01	1.74	$170,957	$117,197	$67,263
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

For their economic analysis of wet scrubbers, Donlin used an emission reduction efficiency of 98.45 percent and a life expectancy of 15 years for the control system. Respectively, both figures are based on p. 2-43 and p. 2-51 of EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2 (EPA 2002)[12]. Donlin's economic analyses also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the POX hot cure tanks. In their economic analysis, Donlin assumed the control unit as a low-energy wet scrubber with a saturated air flow rate range of 1,000 cfm to 90,000 cfm. Donlin also assumed the material used for the wet scrubber would be alloy C-275. A summary of Donlin's economic analysis for wet scrubbers is shown below in Table 11-3.

Table 11-3: Donlin Analysis for Technically Feasible PM Controls (EU IDs 85-87)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.03	1.72	$38,390	$183,245	$106,239
Capital Recovery Factor = 0.1168 (8% for a 15-year life cycle)					

Donlin contends the economic analyses indicates the level of particulate reduction does not justify the use of an ESP or wet scrubber on EU IDs 85 through 87 based on the excessive cost per ton of particulates removed per year.

Donlin proposed to use good operating practices for EU IDs 85 through 87 as BACT for reducing particulate emissions. The particulate BACT emission rate will be 0.40 lb/hr combined for EU IDs 85 through 87.

Department Evaluation of BACT for Particulate Emissions from Pressure Oxidation Hot Cure Tanks

The Department revised the cost analysis for wet ESPs and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department also changed the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA Fact Sheet, Wet Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[14]. The Department also adjusted the cost per unit of flowrate (2002) to the lowest cost, $20/scfm, which is also based on EPA Fact Sheet, Wet Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003) [14]. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the POX hot cure

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14 https://www3.epa.gov/ttn/catc/dir1/fwespwpl.pdf#:~:text=Wet%20ESPs%20are%20used%20in%20situations%20for%20which,wet%20ESP%20applications%20have%20been%20increasing%20%28EPA%2C%201998%29.

15 https://www.epa.gov/sites/default/files/2020-07/documents/cs6ch3.pdf

tanks. A summary of the Department's economic analysis is shown below in Table 11-4.

Table 11-4: Department Analysis for Technically Feasible PM Controls (EU IDs 85-87)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet ESP	0.002	1.75	$85,478	$103,762	$59,284
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for wet scrubbers and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department also adjusted the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2, p. 2-43 (EPA 2002)[12]. The Department also changed the assumptions used to determine the costs of the system. Instead of assuming the material used for the wet scrubber would be alloy C-276, the Department assumed the material would be carbon steel, a cheaper alternative. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the POX hot cure tanks. A summary of the Department's economic analysis is shown below in Table 11-5.

Table 11-5: Department Analysis for Technically Feasible PM Controls (EU IDs 85-87)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.002	1.75	$8,595	$178,373	$101,913
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analyses indicates the level of particulate emissions reduction does not justify the use of an ESP or wet scrubber as BACT for EU IDs 85 through 87. The economic analyses shows the costs per ton of particulate emissions removed per year are excessively high.

Step 5 – Selection of Particulate BACT for Pressure Oxidation Hot Cure

The Department's finding is that BACT for particulate emissions for the pressure oxidation hot cure is as follows:

(a) Particulate emissions from EU IDs 85 through 87 shall be controlled by maintaining good operating practices at all times the units are in operation;

(b) Particulate emissions from EU IDs 85 through 87 shall not exceed 0.4 lb/hr combined averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or demonstratable engineering calculations.

12.0 Electrowinning Cells

The electrowinning cells (EU IDs 91 through 94) are where precious metals are precipitated out of a precious metal bearing solution through electrolysis. The electrowinning cells will emit particulates. The following section provides a BACT review for particulates.

12.1 Particulates

The RBLC was searched for any process name containing "electrowinning" and no determinations were found other than the previous entry for the Donlin Gold Project.

Step 1 – Identification of Particulate Control Technologies for Electrowinning Cells
From research, the Department identified the following technologies as available for particulate control of electrowinning cells:

(a) **Dust Collector**
See control description in Section 4.1.

(b) **ESP**
See control description in Section 4.1.

(c) **Wet Scrubber**
See control description in Section 4.1.

(d) **Good Operating Practices**
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Electrowinning Cells
A dust collector would be technically infeasible for particulate control because of the high moisture content of the exhaust from EU IDs 91 through 94.

Step 3 – Ranking of Remaining Particulate Control Options for Electrowinning Cells
The following control technologies have been identified and ranked for control of particulates from the electrowinning cells:

(a) ESP (>99% Control)
(b) Wet Scrubber (>97% Control)
(c) Good Operating Practices (<40% Control)

Step 4 – Evaluate the Most Effective Controls
These controls will have the most effective reductions on particulate matter emissions from the electrowinning cells while having minimal energy and environmental impacts. However, there is a waste effluent associated with wet scrubbers.

Applicant Proposal
Donlin provided economic analyses for particulates using EPA's Air Pollution Control Manual[7] for the installation of the most effective control technologies (wet ESPs and wet scrubbers) on the electrowinning cells to demonstrate that these controls are not economically feasible for EU IDs 91 through 94. For their economic analysis of wet ESP, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Respectively, both figures are based on EPA Fact Sheet, Wet Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[14] and EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 3, p. 3-50 (EPA 1999)[15]. Donlin's economic analysis also used the Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the electrowinning cells. A summary of Donlin's economic analysis for wet ESP is shown below in Table 12-1.

Table 12-1: Donlin Analysis for Technically Feasible PM Controls (EU IDs 91-94)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet ESP	0.002	0.83	$1,387,864	$321,316	$388,240
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

For their economic analysis of wet scrubbers, Donlin used an emission reduction efficiency of 98.45 percent and a life expectancy of 15 years for the control system. Respectively, both figures are based on p. 2-43 and p. 2-51 of EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2 (EPA 2002)[12]. In their economic analysis, Donlin assumed the control unit as a low-energy wet scrubber with a saturated air flow rate range of 1,000 cfm to 90,000 cfm. Donlin also assumed the material used for the wet scrubber would be alloy C-275. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the electrowinning cells. A summary of Donlin's economic analyses for wet scrubbers is shown below in Table 12-2.

Table 12-2: Donlin Analysis for Technically Feasible PM Controls (EU IDs 91-94)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.01	0.82	$327,840	$274,436	$334,963
Capital Recovery Factor = 0.1168 (8% for a 15-year life cycle)					

Donlin contends the economic analyses indicates the level of particulate reduction does not justify the use of an ESP or wet scrubber on EU IDs 91 through 94 based on the excessive cost per ton of particulates removed per year.

Donlin proposed to use good operating practices for EU IDs 91 through 94 as BACT for reducing particulate emissions. The particulate BACT emission rate will be 0.19 lb/hr combined for EU IDs 91 through 94.

Department Evaluation of BACT for Particulate Emissions from Electrowinning Cells

The Department revised the cost analysis for wet ESPs and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department also changed the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA Fact Sheet, Wet Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[14]. The Department also adjusted the cost per unit of flowrate (2002) to the lowest cost, $20/scfm, which is also based on EPA Fact Sheet, Wet Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[14]. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the electrowinning cells. A summary of the Department's PM economic analyses is shown below in Table 12-3.

Table 12-3: Department Analysis for Technically Feasible PM Controls (EU IDs 91-94)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet ESP	0.001	0.83	$693,932	$212,252	$255,305
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for wet scrubbers and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department adjusted the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2, p. 2-43 (EPA 2002) [12]. The Department also changed the assumptions used to determine the costs of the system. Instead of assuming the material used for the wet scrubber would be alloy C-276, the Department assumed the material would be carbon steel, a cheaper alternative. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the electrowinning cells. A summary of the Department's PM economic analysis is shown below in Table 12-4.

Table 12-4: Department Analysis for Technically Feasible PM Controls (EU IDs 91-94)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.001	0.83	$94,948	$235,713	$283,525
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analyses indicates the level of particulate emissions reduction does not justify the use of an ESP or wet scrubber as BACT for EU ID 91 - 94. The economic analyses show the costs per ton of particulate emissions removed per year are excessively high.

Step 5 – Selection of Particulate BACT for Electrowinning Cells
The Department's finding is that BACT for particulate emissions for the electrowinning cells is as follows:

(a) Particulate emissions from EU IDs 91 through 94 shall be controlled by maintaining good operating practices at all times the unit is in operation;

(b) Particulate emissions from EU IDs 91 through 94 shall not exceed 0.19 lb/hr combined averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

13.0 Mercury Retort

The mercury retort (EU ID 97) is where the precious metal bearing sludge recovered from EU IDs 91 through 94 will be heated to recover mercury before being smelted in EU ID 100. The retort will emit particulates. The following section provides a BACT review for particulates.

13.1 Particulates

The RBLC was searched for any process name containing "retort" and no determinations were found.

Step 1 – Identification of Particulate Control Technologies for the Mercury Retort
From research, the Department identified the following technologies as available for particulate control of retort:

(a) Dust Collector
See control description in Section 4.1.

(b) ESP
See control description in Section 4.1.

(c) Wet Scrubber
See control description in Section 4.1.

(d) Good Operating Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for the Mercury Retort
None of the particulate control technologies listed above are technically infeasible.

Step 3 – Ranking of Remaining Particulate Control Options for the Mercury Retort
The following control technologies have been identified and ranked for control of particulates from the retort:

(a) Dust Collector (>99% Control)

(b) ESP (>99% Control)

(c) Wet Scrubber (>97% Control)

(d) Good Operating Practices (<40% Control)

Step 4 – Evaluate the Most Effective Controls
These controls will have the most effective reductions on particulate matter emissions from the mercury retort while having minimal energy and environmental impacts. However, there is a waste effluent associated with wet scrubbers.

Applicant Proposal
Donlin provided PM economic analyses using EPA's Air Pollution Control Manual[7] for the installation of the most effective control technologies (dry ESPs, wet scrubbers, and dust collectors) on the mercury retort to demonstrate that these controls are not economically feasible for EU ID 97. For their economic analysis of dry ESPs, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Both figures are based on EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[11]. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the mercury retort. A summary of Donlin's economic analyses for dry ESP is shown below in Table 13-1.

Table 13-1: Donlin Analysis for Technically Feasible PM Controls (EU ID 97)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.001	0.13	$141,039	$112,739	$862,730
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

For their economic analysis of wet scrubbers, Donlin used an emission reduction efficiency of 98.45 percent and a life expectancy of 15 years for the control system. Respectively, both figures are based on p. 2-43 and p. 2-51 of EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2 (EPA 2002)[12]. In their economic analysis, Donlin assumed the control unit as a low-energy wet scrubber with a saturated air flow rate range of 1,000 cfm to 90,000 cfm. Donlin also assumed the material used for the wet scrubber would be alloy C-275. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed 8,760 hours of operation per year for the mercury retort. A summary of Donlin's economic analyses for wet scrubbers is shown below in Table 13-2.

Table 13-2: Donlin Analysis for Technically Feasible PM Controls (EU ID 97)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.002	0.13	$50,513	$185,612	$1,434,811
Capital Recovery Factor = 0.1168 (8% for a 15-year life cycle)					

For their economic analysis of dust collectors, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Respectively, both figures are based on p. 1-50 and p. 1-55 of the EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 1 (EPA 1998)[13]. Donlin assumed the control unit as a pulse-jet baghouse. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent, and an assumed

8,760 hours of operation per year for the mercury retort. A summary of Donlin's economic analyses for dust collectors is shown below in Table 13-3.

Table 13-3: Donlin Analysis for Technically Feasible PM Controls (EU ID 97)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.001	0.13	$32,939	$182,092	$1,393,448
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends the economic analyses indicates the level of particulate reduction does not justify the use of an ESP, wet scrubber, or dust collector on EU ID 97 based on the excessive cost per ton of particulates removed per year.

Donlin proposed to use good operating practices for EU ID 97 as BACT for reducing particulate emissions. The particulate BACT emission rate will be 0.03 lb/hr for EU ID 97.

Department Evaluation of BACT for Particulate Emissions from Mercury Retort

The Department revised the cost analysis for dry ESPs by changing the estimated equipment life to 25 years. The Department also changed the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[11]. The Department also adjusted the cost per unit of flowrate (2002) to the lowest value, $10/scfm, which is also based on EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003)[11]. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the mercury retort. A summary of the Department's economic analysis is shown below in Table 13-4.

Table 13-4: Department Analysis for Technically Feasible PM Controls (EU ID 97)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.0001	0.13	$42,739	$97,744	$744,608
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for wet scrubbers by changing the estimated equipment life to 25 years. The Department also adjusted the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA's Air Pollution Control Cost Manual, Sec. 6, Ch. 2, p. 2-43 (EPA 2002)[12]. The Department also changed the assumptions used to determine the costs of the system. Instead of assuming the material used for the wet scrubber would be alloy C-276, the Department assumed the material would be carbon steel, a cheaper alternative. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the mercury retort. A summary of the Department's economic analysis is shown below in Table 13-5.

Table 13-5: Department Analysis for Technically Feasible PM Controls (EU ID 97)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.0001	0.13	$11,688	$179,252	$1,365,539
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for the dust collector control technology by changing the estimated equipment life to 25 years. The Department also changed the control efficiency to

99.9 percent, the maximum control efficiency listed in the EPA's Air Pollution Control Cost Manual, Sec. 6, Ch.1, p. 1-4 (EPA 1998)[13]. The Department kept the other assumptions unchanged including the interest rate of 8% and the assumed 8,760 hours per year of operation for the mercury retort. A summary of the Department's economic analysis is shown below in Table 13-6.

Table 13-6: Department Analysis for Technically Feasible PM Controls (EU ID 97)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.0001	0.13	$32,939	$181,825	$1,385,136
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analyses indicates the level of particulate emissions reduction does not justify the use of a dry ESP, wet scrubber, or dust collector as BACT for EU ID 97. The economic analyses show the costs per ton of particulate emissions removed per year are excessively high.

Step 5 – Selection of Particulate BACT for Mercury Retort

The Department's finding is that BACT for particulate emissions for the mercury retort is as follows:

(a) Particulate emissions from EU ID 97 shall be controlled by maintaining good operating practices at all times the unit is in operation;

(b) Particulate emissions from EU ID 97 shall not exceed 0.03 lb/hr averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

14.0 Laboratories

Three laboratory facilities will be included at DGP, the sample receiving and preparation laboratory (EU IDs 103 and 104), the assay laboratory (EU ID 106), and the metallurgical laboratory (EU IDs 108 and 109). EU IDs 104, 106, and 109 will emit particulates. The following section provides a BACT review for particulates.

14.1 Particulates

The RBLC was searched for any process name containing "lab" and no determinations were found other than the previous entry for the Donlin Gold Project.

Step 1 – Identification of Particulate Control Technologies for Laboratories

From research, the Department identified the following technologies as available for particulate control of fume hoods:

(a) Dust Collector
See control description in Section 4.1.

(b) ESP
See control description in Section 4.1.

(c) Wet Scrubber
See control description in Section 4.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Laboratories

All of the control technologies listed above are technically feasible.

Step 3 – Ranking of Remaining Particulate Control Options for Laboratories
The following control technologies have been identified and ranked for control of particulates from the laboratories:

(a) Dust Collector (>99% Control)

(b) ESP (>90% Control)

(c) Wet Scrubber (50% - 90% Control)

Step 4 – Evaluate the Most Effective Controls
The most effective control technology is a dust collector. The dust collector will have a minimal impact on the environment.

Applicant Proposal
Donlin proposed to install fume hoods with dust collectors for EU IDs 104, 106, and 109 as BACT for reducing particulate emissions. The particulate BACT emission rate will be 0.009 gr/scf for EU ID 104, 0.004 gr/scf for EU ID 106, and 0.009 gr/scf for EU ID 109.

Step 5 – Selection of Particulate BACT for Laboratories
The Department's finding is that BACT for particulate emissions for the laboratories is as follows:

(a) Particulate emissions from EU IDs 104, 106, and 109 shall be controlled with fume hoods and dust collectors operating at all times the units are in operation;

(b) Particulate emissions from EU IDs 104 and 109 shall not exceed 0.009 gr/scf averaged over a 3-hour period;

(c) Particulate emissions from EU ID 106 shall not exceed 0.004 gr/scf averaged over a 3-hour period; and

(d) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

15.0 Reagent Handling for Water Treatment

DGP will include a water conditioning circuit (EU ID 111) with the water treatment plant. The transfer of the water conditioning reagents will generate particulate emissions. The following section provides a BACT review for particulates.

15.1 Particulates

Possible particulate emission control technologies for reagent transfers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 90.019, Lime/Limestone Handling/Kiln/Storage/Manufacturing. Determinations for crushers, silos, fuel tanks, and fuel-fired sources were removed for this analysis. The search results are summarized in Table 15-1.

Table 15-1. Particulate Control for Reagent Handling for Water Treatment

Control Technology	Number of Determinations	Emission Limits (gr/dscf)
Dust Collector, Baghouse, or Filter	39	0.002 to 0.02
Partial Enclosure	1	0.004
Wet Scrubber	3	0.02
No Control Specified	1	0.014

Step 1 – Identification of Particulate Control Technologies for Reagent Handling for Water Treatment

From research, the Department identified the following technologies as available for particulate emission control of reagent handling:

(a) **Dust Collector**
See control description in Section 4.1.

(b) **Enclosure**
See control description in Section 4.1.

(c) **Water Spray**
See control description in Section 4.1.

(d) **ESP**
See control description in Section 4.1.

(e) **Wet Scrubber**
See control description in Section 4.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Reagent Handling for Water Treatment

All of the controls listed above are technically feasible.

Step 3 – Ranking of Remaining Particulate Control Options for Reagent Handling for Water Treatment

The following control technologies have been identified and ranked for control of particulate emissions from reagent handling:

(a) Dust Collector	(>99% Control)
(b) Enclosure	(>99% Control)
(c) ESP	(>90% Control)
(d) Wet Scrubber	(50% - 90% Control)
(e) Water Sprays	(up to 90% Control)

Step 4 – Evaluate the Most Effective Controls

The most effective particulate emissions control for the reagent handling for the water treatment plant is a dust collector. A dust collector will have minimal impact on the environment.

RBLC Review

A review of similar units in the RBLC indicates that dust collectors, enclosures, and water sprays are the primary particulate control technologies used to control particulate emissions for reagent transfers.

Applicant Proposal

Donlin proposed to install a dust collector for EU ID 111 as BACT for particulate emissions. The particulate BACT emissions rate will be 0.02 gr/scf for EU ID 111.

Step 5 – Selection of Particulate BACT for Reagent Handling for Water Treatment

The Department's finding is that BACT for particulate emissions for the reagent handling for water treatment is as follows:

(a) Particulate emissions from EU ID 111 shall be controlled by operating and maintaining a dust collector at all times the unit is in operation;

(b) Particulate emissions from EU ID 111 shall not exceed 0.02 gr/scf averaged over a 3-hour period; and

(c) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

16.0 Mill Reagents Handling

The mill reagents handling will include lime handling and slaking (EU IDs 59, 61, and 63), flocculant handling and mixing (EU ID 65), caustic soda handling and mixing (EU ID 67), copper sulfate handling and mixing (EU ID 69), xanthate (PAX) handling and mixing (EU ID 71), and soda ash handling and mixing (EU IDs 73 and 75).

The mill reagents handling will emit particulates. The following section provides a BACT review for particulates.

16.1 Particulates

Possible particulate emission control technologies for reagent transfers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 90.019, Lime/Limestone Handling/Kiln/Storage/Manufacturing. Determinations for crushers, silos, fuel tanks, and fuel-fired sources were removed for this analysis. The search results are summarized in Table 16-1.

Table 16-1. Particulate Control for Reagent Handling for Mill Reagents Handling

Control Technology	Number of Determinations	Emission Limits (gr/dscf)
Dust Collector, Baghouse, or Filter	39	0.002 to 0.02
Partial Enclosure	1	0.004
Wet Scrubber	3	0.02
No Control Specified	1	0.014

Step 1 – Identification of Particulate Control Technologies for Mill Reagents Handling

From research, the Department identified the following technologies as available for particulate emissions control of mill reagents handling:

(a) Dust Collector
See control description in Section 4.1.

(b) Enclosure
See control description in Section 4.1.

(c) Water Spray
See control description in Section 4.1.

(d) ESP
See control description in Section 4.1.

(e) Wet Scrubber
See control description in Section 4.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Mill Reagent Handling

All of the controls listed above are technically feasible for EU IDs 59, 61, 63, 65, 67, 69, 71, 73, and 75. For EU ID 63 a dust collector is not considered technically feasible due to the moisture from slaking.

Step 3 – Ranking of Remaining Particulate Control Options for Mill Reagent Handling
The following control technologies have been identified and ranked for control of particulate from the mill reagent handling:

(a) Dust Collector	(>99% Control)
(b) Enclosure	(>99% Control)
(c) ESP	(>90% Control)
(d) Wet Scrubber	(50% - 90% Control)
(e) Water Sprays	(up to 90% Control)

For EU ID 63 the following control technologies have been identified and ranked for control of particulates:

(a) Enclosure	(>99% Control)
(b) ESP	(>90% Control)
(c) Wet Scrubber	(50% - 90% Control)
(d) Water Sprays	(up to 90% Control)

Step 4 – Evaluate the Most Effective Controls
The most effective particulate emissions control for the mill reagent handling is a dust collector. For EU ID 63 the most effective control technology for particulate emissions is a wet scrubber or ESP. All of the identified controls will have a minimal impacts on the environment.

RBLC Review
A review of similar units in the RBLC indicates that dust collectors and wet scrubbers are the primary particulate control technologies used to control particulate emissions for reagent transfers.

Applicant Proposal
Donlin proposed to install a dust collector for EU IDs 59, 61, 65, 67, 69, 71, 73, and 75 as BACT for particulate emissions. Donlin proposed a wet scrubber for EU ID 63 as BACT for particulate emissions. The particulate BACT emissions rate will be 0.02 gr/scf for EU IDs 59, 61, 63, 65, 67, 69, 71, 73, and 75.

Step 5 – Selection of Particulate BACT for Mill Reagent Handling
The Department's finding is that BACT for particulate emissions for mill reagent handling is as follows:

(a) Particulate emissions from EU IDs 59, 61, 65, 67, 69, 71, 73, and 75 shall be controlled with dust collectors operating at all times the units are in operation;

(b) Particulate emissions from EU ID 63 shall be controlled with wet scrubbers operating at all times the unit is in operation;

(c) Particulate emissions from EU IDs 59, 61, 63, 65, 67, 69, 71, 73, and 75 shall not exceed 0.02 gr/scf averaged over a 3-hour period; and

(d) Compliance with the proposed emission limits will be demonstrated by providing a manufacturer's emission guarantee or conducting a performance test to obtain an emission rate.

17.0 Fuel Tanks

DGP will have a total of 21 fuel tanks that are significant[16] under Title V (EU IDs 126 - 142, 150 - 152, and 156). The fuel tanks will emit VOCs. The following section provides the BACT review for VOC.

17.1 VOC

Possible VOC emission control technologies for fuel tanks were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 42.005 Petroleum Liquid Storage in Fixed Roof Tanks and 42.006 Petroleum Liquid Storage in Floating Roof Tanks. The search results are summarized in Table 17-1.

Table 17-1. VOC Control for Fuel Tanks

Control Technology	Number of Determinations	Emission Limits (tpy)
Floating Roof	83	0.88 – 384.37
Submerged Fill	28	0.0001 – 72.5
Fixed Roof, White Paint, Federal Requirements	15	15.78[1]
Vapor Combustion Unit	14	0.8 – 28.83
No Control Specified	1	81.57

Table Notes

1. Of the 15 determinations in the RBLC for fixed roofs, white paint, and federal requirements, there was only one determination with an emission limit which is contained in the Table.

Step 1 – Identification of VOC Control Technologies for Fuel Tanks

From research, the Department identified the following technologies as available for VOC control of fuel tanks:

(a) Floating Roof

Floating roof tanks contain a roof that floats on the surface of the liquid that will rise and fall with the liquid level in the tank, creating no vapor space except for when tanks have low liquid levels. External floating roof tanks are designed with a roof consisting of a double deck or pontoon single deck which rests or floats on the liquid being contained. An internal floating roof includes a fixed roof over the floating roof, to protect the floating roof from damage and deterioration. In general, the floating roof covers the entire liquid surface except for a small perimeter rim space. Under normal floating conditions, the roof floats essentially flat and is centered within the tank shell. The floating roof must be designed with perimeter seals (primary and secondary seals) which slide against the tank wall as the roof moves up and down. The use of perimeter seals minimizes emissions of VOCs from the tank. Sources of emissions from floating roof tanks include standing storage loss and withdrawal losses. Standing losses occur due to improper fits between tank seal and the tank shell. Withdrawal losses occur when liquid is removed from the tank, lowering the floating roof, revealing a liquid on the tank walls which vaporize.

(b) Submerged Fill

Submerged filling involves filling a tank through an opening underneath the liquid surface level (pipe opening usually 12" or less from bottom of tank) to minimize the production of vapors. The use of submerged fill during tank loading operations can reduce vaporization of the liquid between 40 – 60% from traditional splash loading

[16] Insignificant Emission Units include operation, loading, and unloading of volatile liquid storage with 10,000-gallon capacity or less, with lids or other closure and storing liquid with a vapor pressure not greater than 80 mm of mercury at 21ºC. [18 AAC 50.326(g)(3)]

operations. Note that the use of submerged fill is a control technique specific to the filling of a tank and does not affect the day-to-day emissions of the tank.

(c) Fixed Roof
A cone or dome shaped roof that is permanently affixed to a liquid storage tank. A fixed roof is considered the baseline of emissions for the fuel tanks.

(d) Vapor Recovery Unit (VRU)
A refrigerated condenser that is used as an air pollution control device for treating emission streams with high VOC concentrations (usually > 5,000 ppmv). VRU are often applied in applications involving gasoline bulk terminals, storage, etc. VRU utilizes condensation to separate one or more of the volatile components of a vapor mixture from the remaining vapors through saturation followed by a phase change. After being separated, the VOCs can be captured, recovered, or routed to be destroyed by a VCU.

(e) Vapor Combustion Unit (VCU)
A VCU, sometimes referred to as an enclosed flare, is an enclosed combustion device. VCUs combust the vent gases inside of the stack, avoiding the aesthetic concerns that can accompany visible flames produced by open flares. More burner tips are provided than for the open flare and the burner tips are located low enough inside the stack that there is no visible flame outside the stack. Air is drawn in through an adjustable opening in the bottom of the flare stack. A continuously lit pilot ensures that vent gases are combusted at the flare tip. A properly operated VCU can achieve a destruction efficiency of 98 percent or greater. The Donlin Gold Project does not currently include the operation of a thermal oxidizer. The addition of a new combustion unit to control emissions from the tanks would create an undesired additional source of emissions which would not justify the offset of the 1.7 tons of combined potential VOC emissions from all the significant tanks on site.

Step 2 – Elimination of Technically Infeasible VOC Control Options for Fuel Tanks
As explained in step 1, the addition of a thermal oxidizer/flare to control emissions would result in the addition of a combustion unit with a continuously lit pilot light that may offset the emissions reduction expected from the fuel tanks, which have modest VOC emissions to begin with. Therefore, a flare or thermal oxidizer is eliminated from further consideration.

Step 3 – Ranking of Remaining VOC Control Options for Fuel Tanks
The following control technologies have been identified and ranked for control of VOC from the tanks:

(a) Floating Roof (99% Control)

(b) VRU (90 % Control)

(c) Submerged Fill (40%-60% Control)

(d) Fixed Roof (Baseline)

Step 4 – Evaluate the Most Effective Controls
A floating roof will have the most effective reductions of VOC emissions from the fuel tanks and will have minimal energy and environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that floating roof is the most common control device for fuel tanks.

Applicant Proposal:

Donlin provided VOC economic analyses using EPA's Air Pollution Control Cost Manual[7] for the installation of the most effective control technologies (VRUs and floating roofs) on the large diesel tanks to demonstrate that these controls are not economically feasible for EU IDs 126 through 140. The smaller EU IDs 141, 142, 150 - 152, and 156 with a potential-to-emit of 0.146 tpy were not included in Donlin's VOC economic analyses. For their economic analysis of VRUs, Donlin used an emission reduction efficiency of 90 percent and a life expectancy of 15 years for the control system. Both figures are based on the EPA's Air Pollution Control Cost Manual, Sec. 3.1, Ch. 2 (EPA 2017)[17]. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed annual throughput of 7,500,000 gal/yr for the large diesel tanks. A summary of Donlin's economic analysis for VRUs is shown below in Table 17-2.

Table 17-2: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 126-140)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Vapor Recovery Unit (VRU)	0.17	1.53	$97,857	$80,027	$52,305
Capital Recovery Factor = 0.1168 (8% for a 15-year life cycle)					

For their economic analysis of internal floating roofs, Donlin used an emission reduction efficiency of 65% percent based off Tanks 4.0.9d. Donlin also used an equipment and installation cost of $308,000 based off a rough estimate given by Allentech, a supplier of custom roofs and other accessories within the petrochemical industry. Donlin used a life expectancy of 27 years, which is the expected lifetime of the mine. Donlin's economic analysis also used the Donlin Gold Project borrowing interest rate of 8.0 percent and an assumed annual throughput of 7,500,000 gal/yr for the large diesel tanks. A summary of Donlin's economic analysis for internal floating roofs is shown below in Table 17-3.

Table 17-3: Donlin Analysis for Technically Feasible VOC Controls (EU IDs 126-140)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Floating Roof	0.59	1.11	$4,620,000	$671,971	$608,118
Capital Recovery Factor = 0.9145 (8% for a 27-year life cycle)					

Donlin contends the economic analyses indicates the level of VOC reduction does not justify the use of VRU or floating roof design on the fuel tanks based on the excessive cost per ton of VOC removed per year.

Donlin proposed to use submerged filling for EU IDs 126 through 142, 150 through 152, and 156 as BACT for reducing VOC emissions. The VOC BACT emission rate will be 1.7 tpy combined for EU IDs 126 through 142, 150 through 152, and 156.

Department Evaluation of BACT for VOC Emissions from Large Diesel Tanks

The Department revised the cost analysis for VRUs and used conservative assumptions to estimate costs. The Department changed the estimated equipment life to 25 years. The Department also changed the direct installation cost to $22,527 (2022) and the total operations & maintenance cost to $14,346 (2022). Both figures are based on Installing Vapor Recovery Units

[17] https://www.epa.gov/sites/default/files/2020-07/documents/cs3-1ch2.pdf

on Storage Tanks, p. 5 (EPA 2006)[18]. The Department kept the other assumptions unchanged including the interest rate of 8% and an assumed annual throughput of 7,500,000 gal/yr for the large diesel tanks. A summary of Department's economic analysis for internal floating roofs is shown below in Table 17-4.

Table 17-4: Department Analysis for Technically Feasible PM Controls (EU IDs 126 - 140)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
VRU	0.17	1.53	$97,136	$35,939	$23,490
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for internal floating roofs by changing the control efficiency to 95 percent based off an estimate given by Allentech's webpage[19]. The Department kept the other assumptions unchanged including the interest rate of 8% and an assumed annual throughput of 7,500,000 gal/yr for the large diesel tanks. A summary of the Department's economic analysis for internal floating roofs is shown below in Table 17-5.

Table 17-5: Department Analysis for Technically Feasible PM Controls (EU IDs 126 - 140)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Internal Floating Roof	0.09	1.62	$4,620,000	$671,971	$416,081
Capital Recovery Factor = 0.0915 (8% for a 27-year life cycle)					

The Department's economic analyses indicates the level of particulate emissions reduction does not justify the use of VRUs or internal floating roofs as BACT for EU IDs 126 through 140. The economic analyses show the costs per ton of VOC emissions removed per year are excessively high.

Step 5 – Selection of VOC BACT for Fuel Tanks

The Department's finding is that BACT for VOC emissions for the 32 fuel tanks at DGP is as follows:

(a) VOC emissions from EU IDs 126 through 142, 150 through 152, and 156 shall controlled with the use of submerged fill when the tanks are filled;

(b) VOC emissions from EU IDs 126 through 142, 150 through 152, and 156 shall not exceed 1.7 tpy combined; and

(c) Initial compliance with the emission limit will be demonstrated by providing the Department with schematics of the fuel tank EU IDs 126 through 142, 150 through 152, and 156 demonstrating that submerged fill is an inherent design.

18.0 Incinerators

DGP will have two incinerators, the camp waste incinerator (EU ID 27) and the sewage sludge incinerator (EU ID 28). The incinerators will emit CO, NOx, SO_2, particulates, VOC, lead, and GHG.[20] The following sections provide a BACT review for each of these pollutants (except SO_2, and lead).

18.1 CO

[18] https://www.epa.gov/sites/default/files/2016-06/documents/ll_final_vap.pdf
[19] https://www.allentech.com/internal-floating-roofs/
[20] Incinerators emit trace amounts of organics, which are hazardous air pollutants regulated under NSPS per Section 129 of the Clean Air Act.

Possible CO emission control technologies for the incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 21.4 and 21.5, Waste Disposal, subcategories Municipal Waste Combustion and Wastewater Treatment Sludge Incineration, as well as a search for the word "incinerator". The search results are summarized in Table 18-1.

Table 18-1. CO Control for Incinerators

Control Technology	Number of Determinations	Emission Limits
Oxidation Catalyst	1	75 ppmvd @ 7% O_2
Good Combustion Practices	6	13 – 100 ppmvd @ 7% O_2 1,359 lb/hr
No Control Specified	1	13 ppmvd @ 7% O_2

Step 1 – Identification of CO Control Technologies for Incinerators
From research, the Department identified the following technologies as available for CO control of incinerators:

(a) Oxidation Catalyst
See control description in Section 3.1.

(a) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible CO Control Options for Incinerators
Both control technologies listed above are technically feasible for CO control.

Step 3 – Ranking of Remaining CO Control Options for Incinerators
The following control technologies have been identified and ranked for control of CO from the boilers and heaters:

(a) Oxidation Catalyst (70 - 90% Control)

(b) GCPs and Clean Fuels (Less than 70% Control)

Step 4 – Evaluate the Most Effective Controls
Catalytic oxidation is the most effective control at reducing CO emissions from EU IDs 27 and 28 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Incinerator efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principal CO control technology for incinerators. The one instance of an oxidation catalyst control system was on a 2,106 ton/day throughput municipal solid waste combustion unit which is substantially larger than EU IDs 27 and 28 which are rated at 11.9 ton/day and 0.058 ton/day respectively.

Applicant Proposal
Donlin provided combined CO economic analyses using EPA's Air Pollution Control Cost Manual[7] for the installation of the most effective control technology (catalytic oxidation) on the large waste camp incinerator and the smaller sewage sludge incinerator to demonstrate that this control is not economically feasible for EU IDs 27 and 28. In their economic analyses for catalytic oxidation, Donlin used the EPA default emission reduction efficiency of 99 percent, the 2022 CEPCI of 785.9, the default life expectancy of 20 years for the control system, and the Donlin Gold Project borrowing interest rate of 8.0 percent. Note that the analyses are per

incinerator for CO emissions reductions. A summary of Donlin's analyses for EU IDs 27 and 28 are shown in Table 18-2 and Table 18-3, respectively:

Table 18-2: Donlin Analysis for Technically Feasible CO Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.009	0.371	$219,380	$114,012	$307,073
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 18-3: Donlin Analysis for Technically Feasible CO Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.005	0.325	$29,172	$29,137	$89,777
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends the economic analyses indicates the level of CO reduction does not justify the use of catalytic oxidation on the incinerators based on the excessive cost per ton of CO removed per year.

Donlin proposed to install incinerators that will comply with NSPS Subpart CCCC (EU ID 27) and NSPS Subpart LLLL (EU ID 28). The CO BACT emission limits will be 17 ppmvd at 7% O_2 for EU ID 27 and 52 ppmvd at 7% O_2 for EU ID 28.

Department Evaluation of BACT for CO Emissions from Incinerators

The Department revised the cost analysis for catalytic oxidation to combine CO and VOC emissions in one calculation and used conservative assumptions to estimate costs. For VOC emissions from EU ID 27, the Department conservatively selected the emissions factor for total organic compounds from multiple chamber incinerators in AP-42, Table 2.1-12. Note that multiple chamber incinerators are the most representative compared to the Permittee's EU ID 27, and this chapter of AP-42 (refuse combustion) did not contain an emissions factor for total nonmethane organics. For VOC emissions from EU ID 28, the Department conservatively selected the emissions factor for total nonmethane organic compounds from uncontrolled incinerators in AP-42, Table 2.2-1. The Department changed the estimated equipment life to 25 years. The Department kept the other assumptions unchanged, including the 99 percent control efficiency, the 2022 CEPCI of 785.9, and the Donlin Gold Project borrowing interest rate of 8.0 percent. Note that the analyses are per incinerator for combined CO and VOC emissions reductions. A summary of the Department's analyses for EU IDs 27 and 28 are shown in Table 18-4 and Table 18-5, respectively:

Table 18-4: Department Analysis for Technically Feasible CO Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.07	6.81	$219,380	$112,221	$16,478
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-5: Department Analysis for Technically Feasible CO Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.004	0.34	$29,172	$28,898	$84,412
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analyses indicates the level of CO and VOC emissions reductions do not justify the use of catalytic oxidation as BACT for EU IDs 27 and 28. The economic analyses show the costs per ton of CO and VOC emissions removed per year are excessively high.

Step 5 – Selection of CO BACT for Incinerators

The Department's finding is that BACT for CO emissions from the incinerators is as follows:

(a) CO emissions from EU IDs 27 and 28 will be controlled by maintaining good combustion practices at all times the units are in operation and installing incinerators designed to comply with NSPS Subparts CCCC for EU ID 27 and LLLL for EU ID 28;

(b) CO emissions from EU ID 27 will not exceed 17 ppmvd at 7% O_2 averaged over a 3-hour period;

(c) CO emissions from EU ID 28 will not exceed 52 ppmvd at 7% O_2 averaged over a 3-hour period; and

(d) Initial compliance with the proposed CO emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

18.2 NOx

Possible NOx emission control technologies for the incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 21.4 and 21.5, Waste Disposal, subcategories Municipal Waste Combustion and Wastewater Treatment Sludge Incineration, as well as a search for the word "incinerator". The search results are summarized in Table 18-6.

Table 18-6. NOx Control for Incinerators

Control Technology	Number of Determinations	Emission Limits
SCR	1	45 ppmvd @ 7% O_2
SNCR	2	110 ppmvd @ 7% O_2
Low-NOx Burner and Flue Gas Recirculation	3	0.06 to 0.08 lb/MMBtu 300 ppmvd @ 7% O_2
Good Combustion Practices	2	170 – 210 ppmvd @ 7% O_2
No Control Specified	1	170 ppmv

Step 1 – Identification of NOx Control Technologies for Incinerators

From research, the Department identified the following technologies as available for NOx control of incinerators:

(a) SCR

See control description in Section 3.2.

(b) Selective Non-Catalytic Reduction (SNCR)
SNCR involves the non-catalytic decomposition of NOx in the flue gas to N_2 and water using reducing agents such as urea or NH_3. The process utilizes a gas phase homogeneous reaction between NOx and the reducing agent within a specific temperature window. The reducing agent must be injected into the flue gas at a location in the unit that provides the optimum reaction temperature and residence time. The NH_3 process (trade name-Thermal DeNOx) requires a reaction temperature window of 1,600°F to 2,200°F. In the urea process (trade name–NO_xOUT), the optimum temperature ranges between 1,600 °F and 2,100 °F.

(c) Low-NOx Burner and Flue Gas Recirculation
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible.

Flue gas recirculation lowers the peak combustion temperature and drops the percentage of oxygen in the combustion air/flue gas mixture, delaying the formation of NOx caused by high flame temperatures.

(d) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible NOx Control Options for Incinerators
All control options listed above are technically feasible.

Step 3 – Ranking of Remaining NOx Control Options for Incinerators
The following control technologies have been identified and ranked for control of NOx from the incinerators:

(a) SCR (70% - 90% Control)

(b) Low-NOx Burner (60% Control)

(c) SNCR (30% - 50% Control)

(d) Good Combustion Practices (<40% Control)

Step 4 – Evaluate the Most Effective Controls
SCR is the most effective NOx control for incinerators. No unusual energy impacts were identified with the addition of SCR to the incinerators. Environmental impacts include the disposal of the spent SCR catalyst when replacement becomes necessary, as well as ammonia slip from the SCR system. Neither the ammonia slip nor the waste disposal of the catalyst would preclude the use of SCR as a potential NOx control device.

RBLC Review
A review of similar units in the RBLC indicates that SCR, SNCR, and low NOx burners are the principal NOx control technologies installed on incinerators.

Applicant Proposal

Donlin provided economic analyses using EPA's Air Pollution Control Cost Manual[7] for the installation of the most effective control technologies (SCR and SNCR) on the camp waste incinerator and the sewage sludge incinerator to demonstrate that these controls are not economically feasible for EU IDs 27 and 28. In their economic analyses of SCR, Donlin used the EPA default emission reduction efficiency of 85 percent, the 2022 CEPCI of 785.9, the default life expectancy of 25 years for the control system, and the Donlin Gold Project borrowing interest rate of 8.0 percent. Note that the analyses are per incinerator for NO_x emissions reductions. A summary of Donlin's analyses for EU IDs 27 and 28 are shown in Table 18-7 and Table 18-8, respectively:

Table 18-7: Donlin Analysis for Technically Feasible NOx Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.14	0.828	$1,815,622	$182,999	$220,915
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-8: Donlin Analysis for Technically Feasible NOx Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.013	0.077	$543,799	$56,396	$729,536
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

For their economic analyses of SNCR, Donlin used the EPA default emission reduction efficiency of 50 percent, the 2022 CEPCI of 785.9, the default life expectancy of 20 years for the control system, and the Donlin Gold Project borrowing interest rate of 8.0 percent. Note that the analyses are per incinerator for NO_x emissions reductions. A summary of Donlin's analyses for EU IDs 27 and 28 are shown in Table 18-9 and Table 18-10, respectively:

Table 18-9: Donlin Analysis for Technically Feasible NOx Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	0.49	0.49	$696,086	$82,192	$168,678
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 18-10: Donlin Analysis for Technically Feasible NOx Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	0.045	0.045	$129,895	$15,290	$336,253
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analyses indicate the level of NO_x reduction does not justify the use of SCR and SNCR on the incinerators based on the excessive cost per ton of NO_x removed per year.

Donlin proposed to use good combustion practices for EU IDs 27 and 28 as BACT for reducing NOx emissions. Using good combustion practices will reduce NOx emissions to below the applicable NOx emission limit in NSPS Subpart CCCC for EU ID 27 and NSPS Subpart LLLL for EU ID 28. The BACT emission rates for NOx will be 23 ppmvd at 7% O_2 for EU ID 27 and 210 ppmvd at 7% O_2 for EU ID 28.

Department Evaluation of BACT for NO_x Emissions from Incinerators

The Department revised the cost analysis for SCRs and used conservative assumptions to estimate costs. The Department changed the removal efficiency from 85 percent to 90 percent to reflect the higher removal efficiency of SCR control systems currently used by industry. The Department kept the other assumptions unchanged including the 25-year estimated life span of the control equipment and the interest rate of 8%. A summary of the Department's economic analyses for SCRs on EU IDs 27 and 28 are shown below in Table 18-11 and Table 18-12. Note that the analyses are per incinerator for NO_x emissions reductions.

Table 18-11: Department Analysis for Technically Feasible NOx Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.093	0.88	$1,815,622	$182,999	$208,642
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-12: Department Analysis for Technically Feasible NOx Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR	0.008	0.082	$543,799	$56,396	$689,006
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analysis for SNCRs and used conservative assumptions to estimate costs. The Department changed the removal efficiency from 50 percent to 90 percent and the equipment life from 20 years to 25 years. These changes are based on the best-case scenarios given in Selective Noncatalytic Reduction, Ch. 1, p. 1-2 (EPA, 2019)[21]. The Department also changed the assumed reagent from urea to ammonia because there was no data available for urea-based SNCR for incinerators from Selective Noncatalytic Reduction, Ch. 1. The Department kept the other assumptions unchanged including the interest rate of 8%. A summary of the Department's economic analyses for SNCRs on EU IDs 27 and 28 are shown below in Table 18-13 and Table 18-14. Note that the analyses are per incinerator for NO_x emissions reductions.

Table 18-13: Department Analysis for Technically Feasible NOx Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	0.093	0.88	$696,086	$76,105	$86,769
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-14: Department Analysis for Technically Feasible NOx Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	0.008	0.082	$129,895	$14,190	$173,365
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

[21] https://www.epa.gov/sites/default/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf

The Department's economic analyses indicates the level of NOx emissions reduction does not justify the use of SCR or SNCR as BACT for the incinerators. The economic analyses show the costs per ton of NOx emissions removed per year are excessively high.

Step 5 – Selection of NOx BACT for Incinerators
The Department's finding is that BACT for NOx emissions from the incinerators is as follows:

(a) NOx emissions from EU IDs 27 and 28 will be controlled by maintaining good combustion practices at all times the units are in operation and installing incinerators designed to comply with NSPS Subparts CCCC for EU ID 27 and LLLL for EU ID 28;

(b) NOx emissions from EU ID 27 will not exceed 23 ppmvd at 7% O_2 averaged over a 3-hour period;

(c) NOx emissions from EU ID 28 will not exceed 210 ppmvd at 7% O_2 averaged over a 3-hour period; and

(d) Initial compliance with the proposed NOx emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

18.3 Particulates

Possible particulate emission control technologies for the incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 21.4 and 21.5, Waste Disposal, subcategories Municipal Waste Combustion and Wastewater Treatment Sludge Incineration, as well as a search for the word "incinerator". The search results are summarized in Table 18-15.

Table 18-15. Particulate Control for Incinerators

Control Technology	Number of Determinations	Emission Limits (mg/dscm at 7% O_2)
Dust Collector/Fabric Filter	3[1]	10 – 24
Good Combustion Practices	2	60 – 270
No control Specified	1	270

Table Notes
1. The three determinations are for one RBLC entry with three different particulate limits: filterable particulates, total $PM_{2.5}$, and total PM_{10}.

Step 1 – Identification of Particulate Control Technologies for Incinerators
From research, the Department identified the following technologies as available for particulate control of incinerators:

(a) Dust Collector
See control description in Section 4.1.

(b) Wet Scrubber
See control description in Section 4.1.

(c) ESP
See control description in Section 4.1.

(d) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Incinerators
All control options listed above are technically feasible.

Step 3 – Ranking of Remaining Particulate Control Options for Incinerators

The following control technologies have been identified and ranked for control of particulates from the incinerators:

(a) Dust Collector (>99% Control)

(b) ESP (>90% Control)

(c) Wet Scrubber (50% - 90% Control)

(d) Good Combustion Practices (<40% Control)

Step 4 – Evaluate the Most Effective Controls

Dust collectors are the most effective control at reducing particulate emissions from EU IDs 27 and 28 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from filter replacement and as necessary. Incinerator efficiency will be minimally impacted by the dust collectors.

RBLC Review

A review of similar units in the RBLC indicates that dust collectors and good combustion practices are the principle particulate control technologies used for incinerators. The one instance of a dust collector was on a 2,106 ton/day throughput municipal solid waste combustion unit which is substantially larger than EU IDs 27 and 28 which are rated at 11.9 ton/day and 0.058 ton/day respectively.

Applicant Proposal

Donlin provided PM economic analyses using EPA's Air Pollution Control Cost Manual[8] for the installation of the most effective control technologies (dry ESPs, wet scrubbers, and dust collectors) on the camp waste incinerator and the sewage sludge incinerator to demonstrate that these controls are not economically feasible for EU IDs 27 and 28. For their economic analyses of dry ESPs, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Both figures are based on EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003). Donlin's economic analyses also used the Donlin Gold Project borrowing interest rate of 8.0 percent, an assumed 8,760 hours of operation per year for EU ID 27, and an assumed 2,920 hours of operation per year for EU ID 28. A summary of the Department's economic analyses for dry ESPs on EU IDs 27 and 28 are shown below in Table 18-16 and Table 18-17. Note that the analyses are per incinerator for PM emissions reductions.

Table 18-16: Donlin Analysis for Technically Feasible PM Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.04	6.83	$167,367	$117,260	$17,160
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 18-17: Donlin Analysis for Technically Feasible PM Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.02	4.84	$141,039	$59,840	$12,369
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

For their economic analyses of wet scrubbers, Donlin used an emission reduction efficiency of 98.45 percent and a life expectancy of 15 years for the control system. Respectively, both figures are based on p. 2-43 and p. 2-51 of EPA Cost Manual, Sec. 6, Ch. 2 (EPA 2002). Donlin's economic analyses also used the Donlin Gold Project borrowing interest rate of 8.0 percent, an assumed 8,760 hours of operation per year for EU ID 27, and an assumed 2,920 hours of operation per year for EU ID 28. In their economic analyses, Donlin assumed the control unit as a low-energy wet scrubber with a saturated air flow rate range of 1,000 cfm to 90,000 cfm. Donlin also assumed the material used for the wet scrubber would be alloy C-275. A summary of Donlin's economic analyses for wet scrubbers on EU IDs 27 and 28 are shown below in Table 18-18 and Table 18-19. Note that the analyses are per incinerator for PM emissions reductions.

Table 18-18: Donlin Analysis for Technically Feasible PM Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.11	6.76	$153,405	$210,813	$31,164
Capital Recovery Factor = 0.1168 (8% for a 15-year life cycle)					

Table 18-19: Donlin Analysis for Technically Feasible PM Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.07	4.79	$24,391	$62,773	$13,108
Capital Recovery Factor = 0.1168 (8% for a 15-year life cycle)					

For their economic analyses of dust collectors, Donlin used an emission reduction efficiency of 99.45 percent and a life expectancy of 20 years for the control system. Respectively, both figures are based on p. 1-50 and p. 1-55 of EPA Cost Manual, Sec. 6, Ch. 1 (EPA 1998). Donlin's economic analyses also used the Donlin Gold Project borrowing interest rate of 8.0 percent, an assumed 8,760 hours of operation per year for EU ID 27, and an assumed 2,920 hours of operation per year for EU ID 28. In their economic analysis, Donlin assumed the control unit as a pulse-jet baghouse. A summary of Donlin's economic analyses for dust collectors on EU IDs 27 and 28 are shown below in Table 18-20 and Table 18-21. Note that the analyses are per incinerator for PM emissions reductions.

Table 18-20: Donlin Analysis for Technically Feasible PM Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.04	6.83	$70,755	$194,295	$28,433
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Table 18-21: Donlin Analysis for Technically Feasible PM Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.02	4.84	$29,412	$63,118	$13,047
Capital Recovery Factor = 0.1019 (8% for a 20-year life cycle)					

Donlin contends that the economic analyses indicate the level of particulate emissions reduction does not justify the use of an ESP, wet scrubber, or dust collector on the incinerators based on the excessive cost per ton of particulate emissions removed per year.

Donlin proposes to use good combustion practices for EU IDs 27 and 28 as BACT for reducing particulate emissions to comply with NSPS Subpart CCCC (EU ID 27) and NSPS Subpart LLLL

(EU ID 28). Particulate BACT emission rates will be 18 mg/dscm at 7% O_2 for EU ID 27 and 60 mg/dscm at 7% O_2 for EU ID 28.

Department Evaluation of BACT for Particulate Emissions from Incinerators

The Department revised the cost analyses for dry ESPs by changing the estimated equipment life to 25 years. The Department also changed the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003). The Department also adjusted the cost per unit of flowrate (2002) to the lowest value, $10/scfm, which is also based on EPA Fact Sheet, Dry Electrostatic Precipitator (ESP) – Wire-Plate Type (EPA 2003). The Department kept the other assumptions unchanged including the interest rate of 8%, an assumed 8,760 hours of operation per year for EU ID 27, and an assumed 2,920 hours of operation per year for EU ID 28. A summary of the Department's economic analyses for dust collectors on EU IDs 27 and 28 are shown below in Table 18-22 and Table 18-23. Note that the analyses are per incinerator for PM emissions reductions.

Table 18-22: Department Analysis for Technically Feasible PM Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.01	6.86	$50,717	$99,465	$14,490
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-23: Department Analysis for Technically Feasible PM Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dry ESP	0.005	4.86	$42,739	$44,845	$9,228
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analyses for wet scrubbers by changing the estimated equipment life to 25 years. The Department also adjusted the control efficiency to 99.9 percent, the maximum efficiency presented in the EPA Cost Manual, Sec. 6, Ch. 2, p. 2-43 (EPA 2002). The Department also changed the assumptions used to determine the costs of the system. Instead of assuming the material used for the wet scrubber would be alloy C-276, the Department assumed the material would be carbon steel, a cheaper alternative. The Department kept the other assumptions unchanged including the interest rate of 8%, an assumed 8,760 hours of operation per year for EU ID 27, and an assumed 2,920 hours of operation per year for EU ID 28. A summary of the Department's economic analyses for dust collectors on EU IDs 27 and 28 are shown below in Table 18-24 and Table 18-25. Note that the analyses are per incinerator for PM emissions reductions.

Table 18-24: Department Analysis for Technically Feasible PM Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.01	6.86	$40,559	$192,176	$27,997
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-25: Department Analysis for Technically Feasible PM Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Wet Scrubber	0.005	4.86	$5,172	$59,640	$12,272
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department revised the cost analyses for dust collectors by changing the estimated equipment life to 25 years. The Department also changed the control efficiency to 99.9 percent, the maximum control efficiency listed in the EPA Cost Manual, Sec. 6, Ch.1, p. 1-4 (EPA 1998). The Department also made minor revisions to the equipment costs. The Department kept the other assumptions unchanged including the interest rate of 8%, an assumed 8,760 hours of operation per year for EU ID 27, and an assumed 2,920 hours of operation per year for EU ID 28. A summary of the Department's economic analyses for dust collectors on EU IDs 27 and 28 are shown below in Table 18-26 and Table 18-27. Note that the analyses are per incinerator for PM emissions reductions.

Table 18-26: Department Analysis for Technically Feasible PM Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.01	6.86	$70,755	$193,736	$28,224
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-27: Department Analysis for Technically Feasible PM Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Dust Collector	0.005	4.86	$29,412	$62,878	$12,939
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analyses indicates the level of particulate emissions reduction does not justify the use of an ESP, a wet scrubber, or a dust collector as BACT for EU IDs 27 and 28. The economic analyses show the costs per ton of particulate emissions removed per year are excessively high.

Step 5 – Selection of Particulate BACT for Incinerators

The Department's finding is that BACT for particulate emissions from the incinerators is as follows:

(a) Particulate emissions from EU IDs 27 and 28 will be controlled by maintaining good combustion practices at all times the units are in operation and installing incinerators designed to comply with NSPS Subparts CCCC for EU ID 27 and LLLL for EU ID 28;

(b) Particulate emissions from EU ID 27 will not exceed 18 mg/dscm at 7% O_2 averaged over a 3-hour period;

(c) Particulate emissions from EU ID 28 will not exceed 60 mg/dscm at 7% O_2 averaged over a 3-hour period; and

(d) Initial compliance with the proposed particulate emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

18.4 VOC

Possible VOC emission control technologies for the incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 21.4 and 21.5, Waste Disposal, subcategories Municipal Waste Combustion and Wastewater Treatment Sludge Incineration, as well as a search for the word “incinerator”. The search results are summarized in Table 18-28.

Table 18-28. VOC Control for Incinerators

Control Technology	Number of Determinations	Emission Limits
Oxidation Catalyst	1	75 ppmvd @ 7% O_2
Good Combustion Practices	2	10 ppmvd @ 7% O_2
No Control Specified	4	10 ppmvd @ 7% O_2 3.0 lb/ton

Step 1 – Identification of VOC Control Technologies for Incinerators
From research, the Department identified the following technologies as available for VOC control of incinerators:

(b) Oxidation Catalyst
See control description in Section 3.1.

(b) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible VOC Control Options for Incinerators
Both control technologies listed above are technically feasible for VOC control.

Step 3 – Ranking of Remaining VOC Control Options for Incinerators
The following control technologies have been identified and ranked for control of VC from the boilers and heaters:

(c) Oxidation Catalyst (70 - 90% Control)

(d) GCPs and Clean Fuels (Less than 70% Control)

Step 4 – Evaluate the Most Effective Controls
Catalytic oxidation is the most effective control at reducing VOC emissions from EU IDs 27 and 28 while having minimal energy and environmental impacts. This system requires no consumables and does not produce waste effluents or by-products aside from catalyst replacement and recycling as necessary. Incinerator efficiency will be minimally impacted by the oxidation catalyst.

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices is the principal VOC control technology for incinerators. The one instance of an oxidation catalyst control system was on a 2,106 ton/day throughput municipal solid waste combustion unit which is substantially larger than EU IDs 27 and 28 which are rated at 11.9 ton/day and 0.058 ton/day respectively.

Applicant Proposal
Donlin proposed to install incinerators that will comply with the dioxin/furan (total mass) NSPS Subpart CCCC limit of 0.58 nano-g/Nm^3 @ 7% O_2 for EU ID 27 and NSPS Subpart LLLL limit of 0.045 nano-g/Nm^3 @ 7% O_2 for EU ID 28.

Department Evaluation of BACT for VOC Emissions from Incinerators

The Department revised the cost analysis for catalytic oxidation to combine CO and VOC emissions in one calculation and used conservative assumptions to estimate costs. For VOC emissions from EU ID 27, the Department conservatively selected the emissions factor for total organic compounds from multiple chamber incinerators in AP-42, Table 2.1-12. Note that multiple chamber incinerators are the most representative compared to the Permittee's EU ID 27, and this chapter of AP-42 (refuse combustion) did not contain an emissions factor for total nonmethane organics. For VOC emissions from EU ID 28, the Department conservatively selected the emissions factor for total nonmethane organic compounds from uncontrolled incinerators in AP-42, Table 2.2-1. The Department changed the estimated equipment life to 25 years. The Department kept the other assumptions unchanged, including the 99 percent control efficiency, the 2022 CEPCI of 785.9, and the Donlin Gold Project borrowing interest rate of 8.0 percent. Note that the analyses are per incinerator for combined CO and VOC emissions reductions. A summary of the Department's analyses for EU IDs 27 and 28 are shown in Table 18-29 and Table 18-30, respectively:

Table 18-29: Department Analysis for Technically Feasible VOC Controls (EU ID 27)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.07	6.81	$219,380	$112,221	$16,478
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

Table 18-30: Department Analysis for Technically Feasible VOC Controls (EU ID 28)

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
Catalytic Oxidation	0.004	0.34	$29,172	$28,898	$84,412
Capital Recovery Factor = 0.0937 (8% for a 25-year life cycle)					

The Department's economic analyses indicates the level of CO and VOC emissions reductions do not justify the use of catalytic oxidation as BACT for EU IDs 27 and 28. The economic analyses show the costs per ton of CO and VOC emissions removed per year are excessively high.

Step 5 – Selection of VOC BACT for Incinerators

The Department's finding is that BACT for VOC emissions from the incinerators is as follows:

(a) VOC emissions from EU IDs 27 and 28 will be controlled by maintaining good combustion practices at all times the units are in operation;

(b) VOC emissions from EU ID 27 will not exceed 3.0 lb/ton averaged over a 3-hour period;

(c) VOC emissions from EU ID 28 will not exceed 1.7 lb/ton averaged over a 3-hour period; and

(d) Initial compliance with the proposed VOC emission limit will be demonstrated by conducting a performance test to obtain an emission rate.

18.5 GHG

Possible GHG emission control technologies for the incinerators were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 21.4 and 21.5, Waste Disposal, subcategories Municipal Waste Combustion and Wastewater

Treatment Sludge Incineration, as well as a search for the word "incinerator". The search results for incinerators are summarized in Table 18-31.

Table 18-31. GHG Control for Incinerators

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices and Clean Fuel	4	3,934 – 64,579 tpy 0.29 lb CO_2e/lb of steam
No Control Specified	1	981 tpy

Step 1 – Identification of GHG Control Technologies for Incinerators

From research, the Department identified the following technologies as available for GHG control of incinerators:

(a) CCS
See control description in Section 3.5.

(b) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible GHG Control Options for Incinerators

CCS is technically infeasible for the reasons stated in Section 3.5.

Step 3 – Ranking of Remaining GHG Control Options for Incinerators

Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

Good combustion practices are the most effective GHG controls for incinerators.

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices is the principal GHG control technology for incinerators.

Applicant Proposal

Donlin proposed good combustion practices to control GHG emissions from the incinerators EU IDs 27 and 28. The GHG BACT emission limit will be 4,023.3 tons per year of GHG emissions combined for EU IDs 27 and 28.

Step 5 – Selection of GHG BACT for Incinerators

The Department's finding is that BACT for GHG emissions from the incinerators is as follows:

(a) GHG emissions from EU IDs 27 and 28 will be controlled by maintaining good combustion practices at all times the units are in operation; and

(b) GHG emissions from EU IDs 27 and 28 will not exceed 4,023.3 tons averaged over any consecutive 12-month period.

19.0 Acidulation and Neutralization Tanks

DGP will have GHG emissions from the acidulation tanks (EU ID 124) and the neutralization tanks (EU ID 125). The following sections provide the GHG BACT review.

19.1 GHG

The RBLC was searched for any process name containing "acidulation" or "neutralization" and no determinations were found. Therefore, possible GHG emission control technologies for the acidulation and naturalization tanks were determined based on research for similar tanks.

Step 1 – Identification of GHG Control Technologies for Acidulation and Neutralization Tanks

From research, the Department identified the following technologies as available for GHG control of the acidulation and neutralization tanks:

(a) CCS
See control description in Section 3.5.

(b) Good Operating Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible GHG Control Options for Acidulation and Neutralization Tanks

CCS is technically infeasible for the reasons stated in Section 3.5.

Step 3 – Ranking of Remaining GHG Control Options for Acidulation and Neutralization Tanks

Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls

Good operating practices are the most effective GHG controls for the acidulation and neutralization tanks.

RBLC Review

A review of similar units in the RBLC indicates that good operating practices is the principal GHG control technology for acidulation and neutralization tanks.

Applicant Proposal

Donlin proposed to use good operating practices. The GHG BACT emission limit will be 273,175 tons per year of GHG emissions combined for EU IDs 124 and 125.

Step 5 – Selection of GHG BACT for Acidulation and Neutralization Tanks

The Department's finding is that BACT for GHG emissions from the acidulation and neutralization tanks is as follows:

(a) GHG emissions from EU IDs 124 and 125 will be controlled by maintaining good operating practices at all times the units are in operation; and

(b) GHG emissions from EU IDs 27 and 28 will not exceed 273,175 tons averaged over any consecutive 12-month period.

20.0 Fugitive Dust from Unpaved Roads

DGP will have fugitive emissions from unpaved roads (EU IDs 158 through 160, & 162) while hauling ore and waste, road graders, maintenance vehicles, and other haul road travel. The unpaved roads will emit particulates. The following sections provide the particulate BACT review.

20.1 Particulates

Possible particulate emission control technologies for fugitives from unpaved roads were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 99.150, Unpaved Roads. The search results are summarized in Table 20-1.

Table 20-1. Particulate Control for Fugitive Dust from Unpaved Roads

Control Technology	Number of Determinations	Control Efficiency (%)
Wetting to Include Chemical and Water Suppressants	17	70 -90
Fugitive Dust Plan to include Speed Limits, Sweeping, and Paving	8	No Data

Step 1 – Identification of Particulate Control Technologies for Fugitive Dust from Unpaved Roads
From research, the Department identified the following technologies as available for particulate control of fugitive dust from unpaved roads:

(a) **Wetting (Chemical and Water Suppressants)**
A spray consisting of chemical suppressants and/or water are used to wet the material to minimize the amount of fugitive dust.

(b) **Fugitive Dust Plan (Speed Reduction and Sweeping)**
Fugitive dust plan to include limiting vehicle speed on unpaved roads and sweeping to decrease the amount of fugitive dust.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Fugitive Dust from Unpaved Roads
All control options listed above are technically feasible.

Step 3 – Ranking of Remaining Particulate Control Options for Fugitive Dust from Unpaved Roads
The following control technologies have been identified and ranked for control of particulates from unpaved roads:

(a) Wetting (70 to 90% Control)

(b) Fugitive Dust Plan (<70% Control)

Step 4 – Evaluate the Most Effective Controls
The most effective control method for fugitive dust from haul roads is the use of wetting to include chemical suppressants and/or water. Environmental impacts from this control method are the effect of the chemicals on the surrounding vegetation.

RBLC Review
A review of similar units in the RBLC indicates that the use of chemical suppressant and water are the principal particulate control methods used for fugitive emissions from unpaved roads.

Applicant Proposal
Donlin proposed to apply both water and a chemical suppressant with the expectation to achieve 90 percent or greater control efficiency. The particulate BACT limit for unpaved roads will be 3,445 tons per year for EU IDs 158 through 160, and 162.

Step 5 – Selection of Particulate BACT for Fugitive Dust from Unpaved Roads
The Department's finding is that BACT for particulate emissions for fugitive dust from the unpaved roads is as follows:

(a) Particulate emissions from EU IDs 158 through 160, and 162 will be controlled by following best practical methods (BPMs) detailed in the Donlin Gold Fugitive Dust Control Plan to include applying water and chemical dust suppressants to achieve a 90% control of fugitive dust emissions; and

(b) Particulate emissions from EU IDs 158 through 160, and 162 will not exceed 3,445 tons averaged over any consecutive 12-month period.

21.0 Fugitive Dust from Material Loading and Unloading

DGP will have fugitive emissions from material loading and unloading (EU IDs 115 through 120). The material loading and unloading will emit particulates. The following sections provide the particulate BACT review.

21.1 Particulates

Possible particulate emission control technologies for fugitive emissions from material loading and unloading were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 99.190, Other Fugitive Dust Sources and filtered to only include material transfer emission sources. The search results are summarized in Table 20-1.

Table 21-1. Particulate Control for Fugitive Dust from Material Loading and Unloading

Control Technology	Number of Determinations	Emission Limit
Enclosures and Baghouses	16	0.0429 – 2.4 lb/hr 0.002 – 0.005 gr/dscf
Dust Control Plan to Include Water Spray and Moisture Content	14	530 tpy 90% control

Step 1 – Identification of Particulate Control Technologies for Fugitive Dust from Material Loading and Unloading

From research, the Department identified the following technologies as available for particulates control of material loading and unloading:

(a) Enclosure
See control description in Section 4.1.

(b) Dust Collector
See control description in Section 4.1.

(c) Water Spray
See control description in Section 4.1.

(d) Moisture Content
See control description in Section 4.1.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Fugitive Dust from Material Loading and Unloading

Add-on controls such as a baghouse or enclosure are not technically feasible because the loading and unloading operations at DGP are mobile.

Step 3 – Ranking of Remaining Particulate Control Options for Fugitive Dust from Material Loading and Unloading

The following control technologies have been identified and ranked for control of particulates from the fugitive dust from unpaved roads:

(a) Water Spray (90% control)

(b) Moisture Content (<90% control)

Step 4 – Evaluate the Most Effective Controls

The most effective control method that is technologically feasible for fugitive dust from material loading and unloading is the use of a water spray. Environmental impact from this control method is minimal.

RBLC Review

A review of similar units in the RBLC indicates that the use of a water spray and moisture monitoring is a principal particulate control methods used for fugitive emissions from material loading and unloading.

Applicant Proposal

Donlin proposed to avoid activities during adverse winds and water work areas, as outlined in the fugitive dust plan. The particulate BACT limit from material loading and unloading will be 530 tons per year for EU IDs 115 through 120.

Step 5 – Selection of Particulate BACT for Fugitive Dust from Material Loading and Unloading

The Department's finding is that BACT for particulate emissions for fugitive dust from the material loading and unloading is as follows:

(a) Particulate emissions from EU IDs 115 through 120 will be controlled by following BPMs detailed in the Donlin Gold Fugitive Dust Control Plan to include material moisture, avoiding activities in adverse winds, and watering work areas; and

(b) Particulate emissions from EU 115 – 120 will not exceed 530 tons averaged over any consecutive 12-month period.

22.0 Fugitive Dust from Wind Erosion

Exposed and active mining areas can be a source of fugitive emissions due to wind erosion.

The wind erosion will emit particulates. The following sections provide the particulate BACT review.

22.1 Particulates

Possible particulate emission control technologies for fugitives from wind erosion were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 99.190, Other Fugitive Dust Sources and filtered to only include wind erosion emission sources. There were no determinations found in the RBLC other than the previous entry for the Donlin Gold Project.

Step 1 – Identification of Particulate Control Technologies for Fugitive Dust from Wind Erosion

From research, the Department identified the following technologies as available for control of fugitive dust from wind erosion:

(a) Water Spray
Water sprays are used to wet the material to minimize the amount of fugitive dust.

(b) Chemical
A spray of chemical suppressants are used to wet the material to minimize the amount of fugitive dust.

(c) Enclosure
See control description in Section 4.1.

(d) Moisture Content
See control description in Section 4.1.

(e) **Wind Block**
A wind block is used to slow wind by deflecting it. They can range from a row of trees to a fabric fence, to an artificial shelter.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Fugitive Dust from Wind Erosion
Add-on controls such as an enclosure or wind block are not technically feasible because of the large exposed areas that may be exposed to wind erosion.

Step 3 – Ranking of Remaining Particulate Control Options for Fugitive Dust from Wind Erosion
The following control technologies have been identified and ranked for control of particulates from unpaved roads:

(a) Chemical (90% control)

(b) Water Spray (90% control)

(c) Moisture Content (<90% control)

Step 4 – Evaluate the Most Effective Controls
The most effective control method for fugitive dust from wind erosion is the use of a chemical suppressant. Environmental impacts from this control method are the effects of the chemical suppressant on the surrounding vegetation.

RBLC Review
A review of similar units in the RBLC indicates that the use of a water spray is the principal particulate control methods used for fugitive emissions from wind erosion.

Applicant Proposal
Donlin proposed to use phased surface disturbance, dozer maintenance of waste facility surfaces, and chemical application. Donlin will also cover the coarse ore stockpile to reduce particulate emissions, and the haul road wind erosion emissions will be controlled with water and chemical application as discussed in Section 20.1. The estimated total fugitive dust emission from wind erosion is 31.6 tons per year from EU ID 161.

Step 5 – Selection of Particulate BACT for Fugitive Dust from Wind Erosion
The Department's finding is that BACT for particulate emissions for fugitive dust from wind erosion is as follows:

(a) Particulate emissions from EU ID 161 will be controlled by following BPMs detailed in the Donlin Gold Fugitive Dust Control Plan to include chemical application and a cover over the coarse ore stockpile; and

(b) Particulate emissions from EU ID 161 will not exceed 31.6 tons averaged over any consecutive 12-month period.

23.0 Drilling and Blasting

DGP will have fugitive emissions from drilling (EU ID 113) and blasting (EU ID 114). The drilling will emit particulates, and the blasting will emit CO, NOx, particulates, and GHG. The following sections provide the CO, NOx, and particulate BACT reviews.

23.1 CO

Possible CO emission control technologies from blasting were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 99.190, Other Fugitive Dust Sources and filtered to only include blasting activities. There were no determinations found in the RBLC other than the previous entry for the Donlin Gold Project.

Step 1 – Identification of CO Control Technologies for Drilling & Blasting
From research, the Department identified the following technologies as available for CO control of drilling and blasting:

(a) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible CO Control Options for Drilling & Blasting
The only control technology listed above is technically feasible.

Step 3 – Ranking of Remaining CO Control Options for Drilling & Blasting
Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Good combustion practices will reduce CO emissions from EU ID 114 (blasting) while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that there is no CO emission control available for blasting outside of those proposed by the Donlin Gold Project.

Applicant Proposal
Donlin proposed to use BPMs including good combustion practices as BACT for CO emissions from blasting. Total emissions from blasting for CO will be approximately 1,921 tons per year for EU ID 114.

Step 5 – Selection of CO BACT for Drilling and Blasting
The Department's finding is that BACT for CO emissions for drilling and blasting is as follows:

(a) CO emissions from EU ID 114 shall be controlled by following BPMs detailed in the Donlin Gold Fugitive Dust Control Plan including practicing good combustion practices; and

(b) CO emissions from EU ID 114 will not exceed 1,921 tons averaged over any consecutive 12-month period.

23.2 NOx

Possible NOx emission control technologies from blasting were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 99.190, Other Fugitive Dust Sources and filtered to only include blasting activities. There were no determinations found in the RBLC other than the previous entry for the Donlin Gold Project.

Step 1 – Identification of NOx Control Technologies for Drilling & Blasting
From research, the Department identified the following technologies as available for NOx control of drilling and blasting:

(a) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible NOx Control Options for Drilling & Blasting
The only control technology listed above is technically feasible.

Step 3 – Ranking of Remaining NOx Control Options for Drilling & Blasting
Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
Good combustion practices will reduce NOx emissions from EU ID 114 (blasting) while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that there is no NOx emission control available for blasting outside of those proposed by the Donlin Gold Project.

Applicant Proposal
Donlin proposed to use BPMs including good combustion practices as BACT for NOx emissions from blasting. Total emissions from blasting for NOx will be approximately 52 tons per year.

Step 5 – Selection of NOx BACT for Drilling and Blasting
The Department's finding is that BACT for NOx emissions for drilling and blasting is as follows:

(a) NOx emissions from EU ID 114 shall be controlled by following BPMs detailed in the Donlin Gold Fugitive Dust Control Plan including practicing good combustion practices; and

(b) NOx emissions from EU ID 114 will not exceed 52 tons averaged over any consecutive 12-month period.

23.3 Particulates

Possible particulate emission control technologies from drilling and blasting were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 99.190, Other Fugitive Dust Sources and filtered to only include drilling or blasting activities. There were no determinations found in the RBLC other than the previous entry for the Donlin Gold Project.

Step 1 – Identification of particulate Control Technologies for Drilling & Blasting
From research, the Department identified the following technologies as available for particulate control of drilling and blasting:

(a) Best Practical Methods (BPMs)
The BPMs for blasting and drilling contained in the Donlin Gold Fugitive Dust Control Plan include allow natural wet weather (rain and snow) or inherent material moisture content to maintain dust control, avoiding drilling and blasting during adverse wind events, quality blast hole stemming to confine blast energy, and wet and/or shrouded drilling.

Step 2 – Elimination of Technically Infeasible Particulate Control Options for Drilling & Blasting
The only control technology listed above is technically feasible.

Step 3 – Ranking of Remaining Particulate Control Options for Drilling & Blasting
Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
BMPs will reduce particulate emissions from EU IDs 113 (drilling) and 114 (blasting) while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that there is no particulate emission control available for drilling and blasting outside of those proposed by the Donlin Gold Project.

Applicant Proposal
Donlin proposed to avoid activities during adverse winds and using blast-hole-stemming and wet and/or shrouded drilling when practical as set out in their fugitive dust plan as BACT for

particulate emissions from drilling and blasting. Total potential particulate emissions from EU IDs 113 and 114 are approximated to be 272.4 tons per year.

Step 5 – Selection of Particulate BACT for Drilling and Blasting
The Department's finding is that BACT for particulate emissions for drilling and blasting is as follows:

(a) Particulate emissions from EU IDs 113 and 114 shall be controlled by following BPMs detailed in the Donlin Gold Fugitive Dust Control Plan; and

(b) Particulate emissions from EU IDs 113 and 114 will not exceed 272.4 tons averaged over any consecutive 12-month period.

23.4 GHG

Possible GHG emission control technologies from drilling blasting were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 99.190, Other Fugitive Dust Sources and filtered to only include drilling or blasting activities. There were no determinations found in the RBLC other than the previous entry for the Donlin Gold Project.

Step 1 – Identification of GHG Control Technologies for Drilling & Blasting
From research, the Department identified the following technologies as available for GHG control of drilling and blasting:

(a) Good Combustion Practices
See control description in Section 3.1.

Step 2 – Elimination of Technically Infeasible GHG Control Options for Drilling & Blasting
The only control technology listed above is technically feasible.

Step 3 – Ranking of Remaining GHG Control Options for Drilling & Blasting
Donlin has accepted the only feasible control option. Therefore, ranking is not required.

Step 4 – Evaluate the Most Effective Controls
BMPs will reduce GHG emissions from EU ID 114 (blasting) while having minimal environmental impacts.

RBLC Review
A review of similar units in the RBLC indicates that there is no GHG emission control available for drilling and blasting outside of those proposed by the Donlin Gold Project.

Applicant Proposal
Donlin proposed to use BPMs including good combustion practices as BACT for GHG emissions from blasting. Total potential GHG emissions from blasting will be approximately 11,780 tons per year.

Step 5 – Selection of Particulate BACT for Drilling and Blasting
The Department's finding is that BACT for GHG emissions for drilling and blasting is as follows:

(a) GHG emissions from EU ID 114 shall be controlled by following BPMs detailed in the Donlin Gold Fugitive Dust Control Plan including practicing good combustion practices; and

(b) GHG emissions from EU ID 114 will not exceed 11,780 tons averaged over any consecutive 12-month period.

APPENDIX C: BACT SUMMARY

Table C-1. CO BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 - 12	17 MW Wartsilla engines (ULSD)	0.18 g/kW-hr	Oxidation Catalyst with Good Combustion Practices
1 - 12	17 MW Wartsilla engines (Natural Gas)	0.12 g/kW-hr	Oxidation Catalyst with Good Combustion Practices
13 & 14	200 kW Airport Generators	4.38 g/kW-hr	Good Combustion Practices & Certified to EPA Tier 4 Final
15 - 17	Boilers and Heaters (Natural Gas)	0.074 lb/MMBtu	Good Combustion Practices
15 - 17	Boilers and Heaters (ULSD)	0.160 lb/MMBtu	Good Combustion Practices
18	Boilers and Heaters (Natural Gas)	0.111 lb/MMBtu	Good Combustion Practices
18	Boilers and Heaters (ULSD)	0.240 lb/MMBtu	Good Combustion Practices
19 – 21, 24, & 25	Burner and Heaters (Natural Gas)	0.082 lb/MMBtu	Good Combustion Practices
19, 20, 22, & 26	Burner and Heaters (ULSD)	0.038 lb/MMBtu	Good Combustion Practices
23	Boilers and Heaters (Natural Gas)	0.039 lb/MMBtu	Good Combustion Practices
27	Camp Waste Incinerator	17 ppmvd at 7% O_2	Good Combustion Practices & 40 CFR 60 Subpart CCCC, Table 5
28	Sewage Sludge Incinerator	52 ppmvd at 7% O_2	Good Combustion Practices & 40 CFR 60 Subpart LLLL, Table 2
29 - 37	Emergency and Black Start Generators	4.38 g/kW-hr	Good Combustion Practices & 40 CFR 60 Subpart IIII
77 & 81	Autoclaves	88 lb/hr	Good Operating Practices
88	Carbon Regeneration Kiln	0.88 lb/hr	Good Operating Practices
113 & 114	Drilling and Blasting	1,921 tpy	Good Combustion Practices

Table C-2. NOx BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 12	17 MW Wartsilla engines (ULSD)	0.53 g/kW-hr	Selective Catalytic Reduction & Good Combustion Practices
1 – 12	17 MW Wartsilla engines (Natural Gas)	0.08 g/kW-hr	Selective Catalytic Reduction & Good Combustion Practices
13 & 14	200 kW Airport Generators	0.60 g/kW-hr	Good Combustion Practices & Certified to EPA Tier 4 Final
15 - 17	Boilers and Heaters (ULSD)	0.131 lb/MMBtu	Flue Gas Recirculation & Good Combustion Practices
15 - 17	Boilers and Heaters (Natural Gas)	0.048 lb/MMBtu	Flue Gas Recirculation & Good Combustion Practices
18	Boilers and Heaters (ULSD)	0.223 lb/MMBtu	Flue Gas Recirculation & Good Combustion Practices
18	Boilers and Heaters (Natural Gas)	0.061 lb/MMBtu	Flue Gas Recirculation & Good Combustion Practices
19, 20, 22, & 26	Burner and Heaters (ULSD)	0.154 lb/MMBtu	Good Combustion Practices

EU ID	Description	BACT Limit	BACT Control
19 - 21, & 24 - 25	Burner and Heaters (Natural Gas)	0.098 lb/MMBtu	Good Combustion Practices
23	Boilers and Heaters (Natural Gas)	0.092 lb/MMBtu	Good Combustion Practices
27	Camp Waste Incinerator	23 ppmvd at 7% O_2	Good Combustion Practices & 40 CFR 60 Subpart CCCC, Table 5
28	Sewage Sludge Incinerator	210 ppmvd at 7% O_2	Good Combustion Practices & 40 CFR 60 Subpart LLLL, Table 2
29 – 34[1]	Emergency Engines > 560 kW	8.0 g/kW-hr	Good Combustion Practices & 40 CFR 60 Subpart IIII
35 – 37[1]	Fire Pump Engines 130 < kW < 225	5.0 g/kW-hr	Good Combustion Practices & 40 CFR 60 Subpart IIII
88	Carbon Regeneration Kiln	0.02 lb/hr	Good Operating Practices
113 & 114	Drilling and Blasting	52 tpy	Best Practical Methods / Fugitive Dust Control Plan

Table Notes
1. Limit includes combined NOx + NMHC

Table C-3. Particulate BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 - 12	17 MW Wartsilla engines (ULSD)	0.29 g/kW-hr	Clean Fuel with GCP
1 - 12	17 MW Wartsilla engines (Natural Gas)	0.13 g/kW-hr	Clean Fuel with GCP
13 & 14	200 kW Airport Generators	0.03 g/kW-hr	GCP; Clean Fuels; & Certified to EPA Tier 4 Final
15 – 20, 22, & 26	Boilers, Heaters, & Burner (ULSD)	0.0254 lb/MMBtu	Clean Fuel & Good Combustion Practices
15 – 21 & 23 - 25	Boilers, Heaters, & Burner (Natural Gas)	0.0075 lb/MMBtu	Clean Fuel & Good Combustion Practices
27	Camp Waste Incinerator	18 mg/dscm at 7% O_2	GCP & 40 CFR 60 Subpart CCCC, Table 5
28	Sewage Sludge Incinerator	60 mg/dscm at 7% O_2	GCP & 40 CFR 60 Subpart LLLL, Table 2
29 - 37	Emergency and Black Start Generators	0.25 g/kW-hr	GCP; Clean Fuels; & 40 CFR 60 Subpart IIII
39, 41 - 43, 46, 48, 50, 52, 55, & 56	Crushers, Apron Feeders, Conveyors	0.01 gr/dscf	Dust Collectors
38, 44, 45, 54, & 58	Rock Breaker, Dump Pocket, Conveyors	0.00048 lb/ton	Enclosures
59, 61, 65, 67, 69, 71, 73, & 75	Mill Reagents Handling	0.02 gr/scf	Dust Collectors
63	Lime Handling Slaker	0.02 gr/scf	Wet Scrubber
77 & 81	Autoclaves	0.22 lb/hr	Venturi Scrubbers
85 - 87	Pressure Oxidation Hot Cure	0.4 lb/hr (Combined)	Good Operating Practices
88	Carbon Regeneration Kiln	0.44 lb/hr	Wet Off-Gas Cooler
91 - 94	Electrowinning Cells	0.19 lb/hr (Combined)	Good Operating Practices
97	Mercury Retort	0.03 lb/hr	Good Operating Practices

EU ID	Description	BACT Limit	BACT Control
100	Induction Smelting Furnace	0.005 gr/dscf	Dust Collector
104	Sample Receiving and Preparation Lab	0.009 gr/dscf	Dust Collectors
106	Assay Laboratory	0.004 gr/dscf	Dust Collector
109	Metallurgical Laboratory	0.009 gr/dscf	Dust Collectors
111	Reagent Handling for Water Treatment	0.02 gr/scf	Dust Collector
113 & 114	Drilling and Blasting	272.4 tpy	Best Practical Methods / Fugitive Dust Control Plan
115 - 120	Material Loading and Unloading	530 tpy	Best Practical Methods / Fugitive Dust Control Plan
158 – 160, & 162	Unpaved Roads	3,445 tpy	Chemical and Water Dust Suppressants
161	Fugitive Dust from Wind Erosion	31.6 tpy	Best Practical Methods / Fugitive Dust Control Plan

Table C-4. VOC BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 – 12	17 MW Wartsilla engines (ULSD)	0.21 g/kW-hr	Oxidation Catalyst & Good Combustion Practices
1 – 12	17 MW Wartsilla engines (Natural Gas)	0.09 g/kW-hr	Oxidation Catalyst & Good Combustion Practices
13 & 14	200 kW Airport Generators	0.29 g/kW-hr	Good Combustion Practices & Certified to EPA Tier 4 Final
15 - 20	Boilers and Heaters (ULSD)	0.00154 lb/MMBtu	Good Combustion Practices
15 - 21 and 23 - 25	Boilers, Heaters, and Burner (Natural Gas)	0.0054 lb/MMBtu	Good Combustion Practices
22 and 26	Burner and Heaters (ULSD)	0.0026 lb/MMBtu	Good Combustion Practices
27	Camp Waste Incinerator	3.0 lb/ton	Good Combustion Practices
28	Sewage Sludge Incinerator	1.7 lb/ton	Good Combustion Practices
29 - 34[1]	Emergency Engines > 560 kW	8.0 g/kW-hr	Good Combustion Practices & 40 CFR 60 Subpart IIII
35 - 37[1]	Fire Pump Engines 130 < kW < 225	5.0 g/kW-hr	Good Combustion Practices & 40 CFR 60 Subpart IIII
77 & 81	Autoclaves	0.04 lb/hr	Carbon Adsorber
88	Carbon Regeneration Kiln	0.44 lb/hr	Good Operating Practices
126 – 142, 150 – 152, & 156	Fuel Tanks	1.7 tpy	Submerged Fill

Table Notes
1. Limit includes combined NOx + NMHC

Table C-5. GHG BACT Limits

EU ID	Description	BACT Limit	BACT Control
1 - 12	17 MW Wartsilla engines (ULSD)	1,233,790 tpy combined	Good Combustion Practices
1 - 12	17 MW Wartsilla engines (Natural Gas)	870,501 tpy combined	Good Combustion Practices
13 - 14	200 kW Airport Generators	2,691 tpy combined	Good Combustion Practices
15 - 26	Boilers, Heaters, & Burner (ULSD and Natural Gas)	176,775 tpy combined	Good Combustion Practices
27 & 28	Camp Waste and Sewage Sludge Incinerators	4,023.3 tpy	Good Combustion Practices
29 - 37	Emergency and Black Start Generators	3,007 tpy	Good Combustion Practices
77 & 81	Autoclaves	37,659 tpy combined	Good Operating Practices
113 & 114	Drilling and Blasting	11,780 tpy	Good Combustion Practices
124 & 125	Acidulation and Neutralization Tanks	273,175 tpy	Good Operating Practices

APPENDIX D: MODELING REPORT

Alaska Department of Environmental Conservation

Air Permit Program

Review of Donlin Gold LLC's Ambient Demonstration for the Donlin Gold Project

Construction Permit AQ0934CPT02

Prepared by: James Renovatio December 12, 2022

Table of Contents

1. INTRODUCTION

This report summarizes the Alaska Department of Environmental Conservation's (Department's) findings regarding the ambient analysis submitted by Donlin Gold, LLC (Donlin) for the Donlin Gold Project. Donlin submitted this analysis in support of their 29 October, 2021 application for a Prevention of Significant Deterioration (PSD) permit (AQ0934CPT02). The Donlin Gold project triggers PSD review for oxides of nitrogen (NOx), carbon monoxide (CO), total particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM-10), particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHG).

Donlin provided the source impact analysis required under 40 CFR 52.21(k), pre-construction monitoring analysis required under 40 CFR 52.21(m)(1), and additional impact analysis required under 40 CFR 52.21(o). They demonstrated that operating the project emissions units (EUs) within the restrictions listed in this report will not cause or contribute to a violation of the following Alaska Ambient Air Quality Standards[1] (AAAQS) listed in 18 AAC 50.010: one-hour and annually averaged nitrogen dioxide (NO_2); one-hour and eight-hour carbon monoxide (CO); 24-hour particulate matter with an aerodynamic diameter of 10 microns or less (PM-10); 24-hour and annually averaged particulate matter with an aerodynamic diameter of 2.5 microns or less (PM-2.5); and eight-hour ozone (O_3). Donlin also demonstrated that the project impacts will not cause or contribute to a violation of the following Class II maximum allowable increases (increments) listed in 18 AAC 50.020: annually averaged NO_2, 24-hour PM-10, annually averaged PM-10, 24-hour PM-2.5, and annually averaged PM-2.5.

2. REPORT OUTLINE

The Department's findings regarding Donlin's approach to meet the pre-construction monitoring requirement under 40 CFR 52.21(m) is described in Section 4. The Department's findings regarding the additional impact analysis under 40 CFR 52.21(o) is described in Section 7.

Donlin used a multifaceted approach to address the ambient demonstration requirements under 40 CFR 52.21(k). They used computer analysis (modeling) to predict the NO_2, CO, PM-10, and direct PM-2.5 air quality impacts; ambient data and qualitative discussion to characterize the existing secondary PM-2.5 impacts; and a qualitative approach to address the ambient O_3 and project-related secondary PM-2.5 impacts. The Department's findings regarding Donlin's NO_2, CO, PM-10 and PM-2.5 assessments are in Section 5. Its findings regarding their qualitative O_3 analysis is in Section 6.

3. BACKGROUND

Donlin is proposing to construct and operate an open-pit gold mine. Salient features of the proposed construction include: tailings and waste rock facilities; a process plant with a nominal

[1] There are no ambient demonstration requirements for GHG emissions since there are no GHG AAAQS or increments.

production rate of 59,000 short tons (tons) of ore per day; a 220 megawatt (MW) power plant; and various supporting facilities.

The Department issued Air Quality Control Construction Permit AQ0934CPT01 to Donlin on 30 September, 2017. They are authorized to operate under this active permit, though current application materials indicate that Donlin has yet to commence construction of the stationary source. AQ0934CPT01 will be rescinded and replaced with AQ0934CPT02 upon issuance of the latter. Previous permitting efforts include an owner requested limit (ORL) authorization AQ0934ORL01, which was rescinded following the Department's issuance of AQ0934CPT01.

Additional information regarding Donlin's proposed project, its triggered permit classifications, and the ambient demonstration requirements for those classifications are discussed subsequently.

3.1. Project Location and Area Classification

The stationary source will be situated within the Kuskokwim Mountain region of western Alaska, approximately 450 kilometers (km) west of Anchorage and 15 km north of the community of Crooked Creek. This area is unclassified in regard to compliance with the AAAQS. It is located within a Class II area of the South Central Alaska Intrastate Air Quality Control Region for the purpose of compliance with increment. The project is approximately 315 km from the nearest Class I area, Denali National Park (Denali).

3.2. Project Classification

Donlin's project triggers PSD review under 18 AAC 50.306 for the pollutants and regulatory requirements discussed under the Introduction section of this report. Their project is also subject to the requirements for minor permits classified under:

- 18 AAC 50.502(b)(3), for rock crushers with a rated capacity of five tons-per-hour (tph) or greater;
- 18 AAC 50.508(5), for ORLs to avoid
  - PSD review for the emissions of sulfur dioxide (SO_2); and
  - classification as a major source of hazardous air pollutants; and
- 18 AAC 50.508(6), for their request to revise/rescind AQ0934CPT01.

The provisions of the minor permit will be issued as a part of the PSD permit under 18 AAC 50.502(a)(1).

3.3. Ambient Demonstration Requirements

The State of Alaska's PSD requirements are described in 18 AAC 50.306. PSD applicants must essentially comply with the federal PSD requirements in 40 CFR 52.21. Except as noted in 40 CFR 52.21(i), the ambient requirements include:

- A Source Impact Analysis, i.e., an ambient demonstration for the PSD-triggered pollutants with an associated ambient air quality standard or increment, per 40 CFR 52.21(k);
- An Air Quality Analysis, i.e., pre-construction monitoring data, for the PSD-triggered pollutants with an associated ambient air quality standard or increment, per 40 CFR 52.21(m);
- An Additional Impact Analysis per 40 CFR 52.21(o); and
- A Class I Impact Analysis, for stationary sources that may affect a Class I area, per 40 CFR 52.21(p).

Donlin's project is sufficiently distant from Denali that it does not warrant a Class I Impact Analysis. The Department, nevertheless, notified[2] the National Park Service (NPS) about the proposed project by e-mail on 23 November, 2021. It articulated an understanding that the NPS would not be requesting a Class I assessment under 40 CFR 52.21(p) unless requested. The NPS provided tacit approval of the Department's understanding by not issuing a response.[3] The Department notes that Donlin's proposed project and approach to demonstrate ambient impacts has not meaningfully changed from that submitted in support of AQ0934CPT01. Department staff, therefore, continue to rely upon their previous findings as appropriate; see the modeling report for said permit for detail.

Applicants subject to the requirements for permits classified under 18 AAC 50.502(b) do not need to submit an ambient demonstration unless requested by the Department in comport with 18 AAC 50.540(c)(2)(D). The Department did not request a demonstration under the former since Donlin's application contemporaneously triggered multi-pollutant modeling requirements in association with its PSD classification. There are no ambient air demonstration requirements associated with their classification under 18 AAC 50.508(5).

The recission of AQ0934CPT01 warrants classification under 18 AAC 50.508(6). This classification requires an evaluation of the potential impacts to an underlying ambient demonstration under 18 AAC 50.540(k)(3)(C). Donlin met this requirement by submitting a revised ambient demonstration with their application materials.

3.4. Modeling Protocol Submittal

Donlin did not provide a modeling protocol in advance of their 29 October, 2021 application for AQ0934CPT02. The Department notes, however, that they previously provided a protocol in support of their application for AQ0934CPT01 that remains representative of their current approach. The Department, therefore, continues to rely upon its review of

[2] In accordance with the requirements of 40 CFR 52.21(p).

[3] E-mail from D. Jones (Department) to A. Stacey, C. Collins, et. al. (NPS); *Donlin Gold LLC, Donlin Gold Project PSD Construction Permit Application & 3rd PSD Construction Extension Request*; 23 November, 2021.

Donlin's 10 July, 2015 modeling protocol[4] as it relates to key aspects[5] of their modeled approach for AQ0934CPT02.

3.5. Application Submittal and Amendments

Donlin submitted an application for AQ0934CPT02 to the Department on 29 October, 2021. They provided three supplemental submissions by e-mail on the 9th of March, 24th of March, and 6th of May, 2022. The supplemental submissions were prepared in response to Department requests for additional information and generally address the PSD requirements under 40 C.F.R. 52.21(j) and discrete EU emissions assumptions.

3.6. PM-2.5 Minor Source Baseline Date

Donlin's application for PSD Construction Permit AQ0934CPT01 established a PM-2.5 *minor source baseline date* for the South Central Alaska Intrastate Air Quality Control Region. This date is 15 October, 2015, or the date the Department found said application to be complete as noted in Table 2 of 18 AAC 50.015. Subsequent increases in minor source PM-2.5 emissions within the region will therefore be increment consuming.[6]

4. PRE-CONSTRUCTION MONITORING DATA

40 CFR 52.21(m)(1) requires PSD applicants to provide ambient air monitoring data that characterizes existing air quality in the vicinity of the proposed project. The requirement is applicable to pollutants that are subject to PSD review and have a National Ambient Air Quality Standard (NAAQS).[7] Existing pollutant concentrations or project impacts less than the applicable Significant Monitoring Concentrations (SMCs) in 40 CFR 52.21(i)(5)[8] do not warrant submission of these data. For those pollutants where monitoring is required, the data are to be collected prior to construction, i.e. as pre-construction monitoring. An applicant may separately use monitoring data to characterize natural and anthropogenic impacts in the project area that are not readily defined through dispersion modeling, i.e. *background* data. Ambient monitoring data used to characterize background impacts are intended to better estimate the cumulative impacts from a proposed project and are distinct from the requirements for pre-construction monitoring; see Section 5.17 for detail on Donlin's use of background data.

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[4] As approved with comment on 28 September, 2015.

[5] Salient aspects addressed in the modeling protocol for AQ0934CPT01, and in subsequent pre-application discussions, include updates to fugitive source parameters and receptors, and a request to use the U.S. EPA's ADJ_U* surface friction velocity parameter. ADJ_U* transitioned from an alternative modeling technique to a regulatory option in EPA's 17 January, 2017 revision to the *Guideline on Air Quality Models*.

[6] The Department's minor source baseline dates for PSD increments are established in accordance with 40 CFR 52.21(b)(14)(ii), which the Department has adopted by reference in 18 AAC 50.040(h). A narrative of the PSD increment concept and associated baseline dates may be found in the October 20, 2010 Federal Register notice for the PM-2.5 increment program (Pages 64864 – 64907 of Federal Register Volume 75, No. 202).

[7] EPA has the authority under 40 CFR 52.21(m)(1)(ii) to require pre-construction monitoring for PSD-triggered pollutants that do not have a NAAQS (when they have shown a need for the data), but they have not made this determination for those pollutants.

[8] The District of Columbia Circuit Court of Appeals vacated the PM-2.5 SMC on January 22, 2013. Therefore, projects that trigger PSD review for PM-2.5 must include pre-construction monitoring data, regardless of the project impacts.

Pre-construction monitoring data must be collected at a location and in a manner that is consistent with the U.S. Environmental Protection Agency's (EPA's) *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA-450/4-87-007), which the Department has adopted by reference in 18 AAC 50.035(a)(5). In summary, the data must be collected at the location(s) of existing and proposed maximum impacts, current, and meet the PSD quality assurance requirements described in 18 AAC 50.215(a).

Donlin met their pre-construction monitoring requirements by collecting 12 or more months of PSD-quality ambient data for all PSD-triggered pollutants with a NAAQS. They collected the pollutant data at the New Air Station (NAS) monitoring site, situated approximately 300 meters (m) southeast of their exploration camp site; see Figure 1 for detail.

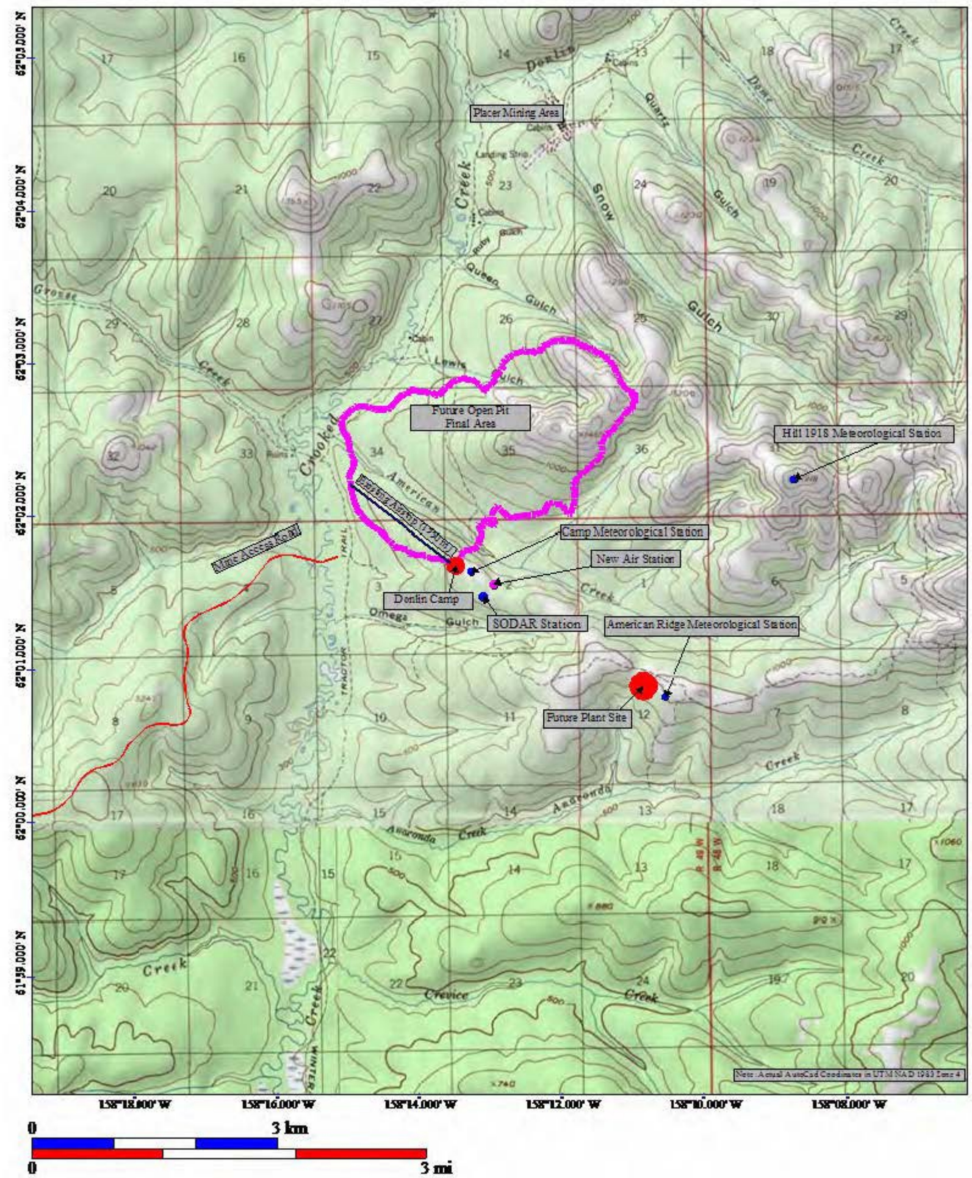

Figure 1. Donlin Creek Project Meteorological and Air Quality Monitoring Stations

A notable, but immaterial exception to Donlin's aforementioned data collection effort is germane to their PM-10 pre-construction monitoring. Donlin collected the first two months of their July 2006 through June 2007 PM-10 data at the 'Camp' meteorological station. They subsequently relocated the PM-10 monitor to the NAS site due to expansion of their exploration camp. The Department conducted a site visit in September of 2006 and determined that the relocation did not warrant a restart of the monitoring period.

The date of initial data collection and duration of monitoring period varied by pollutant. Donlin prepared multiple Quality Assurance Project Plans (QAPPs) for Department review and approval to ensure an appropriate approach for obtaining ambient data was observed. They also submitted the subsequent data sets for Department review and approval. Table 1 provides a pollutant-specific summary of the resulting periods with PSD-quality data.

Table 1. Pre-Construction Monitoring Summary

Pollutant	Avg. Period	Monitoring Period(s)	Max. Conc. (µg/m³)	AAAQS (µg/m³)	*% of AAAQS*
NO_2	One-hour	Nov. 2006 – Nov. 2007; Jan. – Dec. 2008; Dec. 2010 – Nov. 2011; April 2012 – April 2013	**21**	188	*11*
	Annual		**1.4**	100	*2*
CO	One-hour	Nov. 2006 – Nov. 2007; Jan. – Dec. 2008	**687**	40,000	*2*
	Eight-hour		**458**	10,000	*5*
O_3	Eight-hour	Dec. 2010 – Nov. 2011; April 2012 – April 2013	**100**	140	*71*
PM-10	24-hour	July 2006 – June 2007; July 2007 – June 2008	**14**	150	*9*
PM-2.5	24-hour	Jan. – Dec. 2008	**6.8**	35	*19*
	Annual		**2.3**	12	*19*

Table Note: Some values are different from those provided by Donlin in their application materials. These slight differences are due to variation in rounding practices when converting values from a volumetric basis to a mass basis. None of the differences are substantive, nor do they alter the conclusion that the measured concentrations currently demonstrate compliance with the AAAQS.

The AAAQS and maximum concentrations presented in Table 1 are measured according to the form of the given AAAQS. The Department notes that it is reporting the gaseous pollutants on a mass basis in micrograms per cubic meter (µg/m³), which is the convention used in modeling, rather than on a volumetric basis, e.g. in parts-per-million (ppm), which is the convention typically used in monitoring reports. Particulate pollutants are measured and reported on a mass basis.

5. SOURCE IMPACT ANALYSIS

Donlin performed a cumulative modeling analysis to estimate their NO_2, CO, PM-10 and direct PM-2.5 impacts. The various aspects of their analysis are discussed below.

5.1. Approach

Donlin performed multiple sets of model runs for each pollutant and averaging period in support of their 29 October, 2021 PSD application. One group of runs included a full receptor grid, described in Section 5.16, and a modeled characterization of merged exhaust plumes from the primary power plant engines, discussed in Section 5.8.2. Their other model runs entail a *hot spot* analysis of areas anticipated to contain maximum impacts, which used a higher density receptor placement. The Department notes that Donlin previously provided a single plume stack sensitivity analysis for the primary power plant engines and full receptor grid in support of their application for AQ0934CPT01. This sensitivity analysis offered consistent estimated results with only marginal variation in the maximum impacts. The Department finds that it remains representative noting a lack of meaningful revision to the modeled approach associated with said permit.

5.2. Model Selection

There are a number of air dispersion models available to applicants and regulators. EPA lists these models in their *Guideline on Air Quality Models* (Guideline), which the Department has adopted by reference in 18 AAC 50.040(f). Donlin used EPA's AERMOD Modeling System (AERMOD) for their ambient analysis. AERMOD is an appropriate modeling system for this permit application.

The AERMOD Modeling System consists of three major components: AERMAP, used to process terrain data and develop elevations for the receptor grid and EUs; AERMET, used to process the meteorological data; and the AERMOD dispersion model, used to estimate the ambient pollutant concentrations. Donlin used the most current version of each component at the time of their application submission: AERMAP version 18081; AERMET version 21112; and AERMOD version 21112.

5.3. Meteorological Data

AERMOD requires hourly meteorological data to estimate plume dispersion. A *minimum* of one-year of site-specific data, or five years of representative National Weather Service (NWS) data is required, per Section 8.3 of the Guideline. When modeling with site-specific data, the Guideline states that up to five years should be used, when available, to account for year-to-year variation in meteorological conditions.

Donlin used one year of site-specific data collected at their 'Camp' meteorological station from August, 2020 through July, 2021. They used upper air data from the nearest NWS upper air station in McGrath, Alaska, which is appropriate for the proposed project. Donlin supplemented their surface data with concurrent NWS cloud cover data from Sleetmute, Alaska. Missing cloud cover data from Sleetmute was substituted with NWS cloud cover data from Aniak, Alaska.

The Department previously approved Donlin's QAPP for the Camp meteorological station and provided findings on associated data. It approved the former approach during the pre-application review for AQ0934CPT01 as summarized below. Donlin provided a regional cloud cover analysis[9] on 23 October, 2013. The Department supplemented Donlin's analysis with its own review of regional cloud cover data. It subsequently determined[10] that the Sleetmute cloud cover data would be representative of the expected cloud cover at the project site. In a 16 January, 2015 teleconference, Donlin requested the substitution of Aniak or McGrath data for missing Sleetmute data based on the findings of their October 2013 submittal. The Department provided a response on 3 February, 2015 indicating that Aniak data could be substituted for missing Sleetmute data, but cloud cover data from McGrath, or Holy Cross, could not be used.[11] The Department continues to find this approach appropriate for AQ0934CPT02. Detail regarding the subject meteorological data is subsequently discussed.

5.3.1. Quality Assurance Review

Site-specific meteorological data must meet the PSD quality assurance requirements outlined in EPA's *Meteorological Monitoring Guidance for Regulatory Modeling Applications*, per 18 AAC 50.215(a)(3). Donlin submitted their meteorological data for Department approval following the associated 12-month collection period. The Department has used various term contractors to review Donlin's meteorological data on its behalf, however, the final decision regarding data acceptability remains with the Department. The site-specific meteorological parameters used in Donlin's modeling analysis are PSD-quality.

5.3.2. Meteorological Data Processing

Donlin correctly processed the meteorological data using AERMET. However, the following topics warrant additional discussion.

5.3.1.1 Low Wind Speed Adjustments

Donlin used the ADJ_U* option in AERMET to adjust the surface friction velocity. EPA developed this option to correct AERMOD's tendency to overpredict impacts under stable, low wind conditions. The ADJ_U* algorithm was initially introduced as

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9 Donlin provided this analysis in a 23 October, 2013 e-mail from N. Enos (Donlin) to A. Schuler (Department); *RE: ADEC Answer to Donlin Cloud Cover Question*. They included a 10 October, 2013 technical memorandum from Air Sciences, *Relevance of Ceiling Height and Cloud Cover in AERMET/AERMOD*, as an attachment.

10 The Department informed Donlin of its decision to accept Sleetmute cloud cover data in an 10 October, 2013 e-mail from Alan Schuler (Department) to Nick Enos (Donlin); *Donlin May Use Sleetmute Cloud Cover Data*.

11 E-mail from James Renovatio (Department) to Mike Rieser (Donlin); *FW: Cloud cover for Donlin*; 3 February, 2015.

an alternative modeling technique under both EPA and Department rule.[12] EPA has subsequently adopted the ADJ_U* algorithm as a regulatory option in its January 2017 revision to the Guideline. The Department notes that Donlin previously used this option as currently proposed as an element of their approach in AQ0934CPT01. Additional discussion regarding the appropriateness of its proposed use is provided in the Modeling Report for that permit.

5.3.1.2 Surface Characteristics

AERMET requires the area surrounding the meteorological tower to be characterized with regard to the following three surface characteristics: noon-time albedo, Bowen ratio, and surface roughness length. EPA has provided additional guidance regarding the selection and processing of the values used to represent these surface characteristics in their *AERMOD Implementation Guide*. They also developed a computer program, AERSURFACE, to determine the applicable surface characteristics from the U.S. Geological Survey (USGS) National Land Cover Data (NLCD) archives.

Donlin used AERSURFACE to process 2016 NLCD data in developing the surface parameters for their Camp meteorological station. A summary of these parameters is presented in Sections 3.5.1.1 and 3.5.1.2 of Appendix D to their 29 October, 2021 application.

5.4. Coordinate System

Air quality models need to know the relative location of the EUs, applicable structures, and receptors to properly estimate ambient pollutant concentrations. Therefore, applicants must use a consistent coordinate system in their analysis. Donlin used Zone 4 of the Universal Transverse Mercator (UTM) system within the 1983 North American Datum. This is a typical approach in AERMOD assessments and is appropriate for the current project.

5.5. Terrain

Terrain features can influence plume dispersion and the resulting ambient concentration. Digitized terrain elevation data is therefore generally included in an AERMOD analysis. AERMOD's terrain preprocess, AERMAP, utilizes the terrain data to obtain the base elevations for the modeled EUs, buildings, and receptors; and to calculate a *hill height scale* for each receptor.

Donlin used National Elevation Dataset (NED) files for their terrain dataset. NED is the current terrain elevation dataset provided by the USGS. Their use of NED data is therefore reasonable and appropriate.

[12] EPA proposed adopting the ADJ_U* algorithm as a regulatory modeling option as part of a 29 July, 2015 proposal to revise the Guideline. EPA also proposed a second modeling option, 'LOWWIND3', that could be used with or without the ADJ_U* option, to further mitigate the low wind speed issue in AERMOD. Donlin did not request to use this option, nor did they use the LOWWIND3 option in their ambient demonstration.

5.6. EU Inventory

Donlin included the proposed NOx, PM, PM-10, and PM-2.5-emitting EUs in their respective AAAQS/increment demonstrations; and the proposed CO-emitting EUs in their CO AAAQS demonstrations. Detail regarding the modeled EU inventory is subsequently discussed.

5.6.1. General Discussion

Donlin has proposed the operation of various equipment and emissions-generating processes. EUs associated with the former may be considered within the following general categories:

- Mining Activities;
- Process and Refining;
- Power Generation;
- Boilers and Heaters;
- Incinerators;
- Emergency Equipment;
- Access Roads;
- Mobile Machinery Tailpipes; and
- Liquid Storage Tanks

A comprehensive inventory of EUs is available in Appendix B of Donlin's 29 October, 2021 PSD application. Figure 3-7 in Appendix D of said application illustrates the relative location of sources within the modeled domain. The combustion-related sources are proposed to fire either natural gas or ultra-low sulfur diesel (ULSD). Donlin's application materials indicate that select EUs will be dual-fuel capable.

Donlin used the OPENPIT option in AERMOD to characterize the drilling, material extraction, loading and unloading, dozing, and machinery emissions within the pit area. They designated the remaining EUs as either point, volume, or area sources. The modeled emission rates and various aspects of the applicable source characterizations are discussed in Sections 5.7 through 5.11 of this report.

5.6.2. Secondary Emissions

PSD applicants must include *secondary emissions* in their ambient demonstration in accordance with 40 CFR 52.21(k)(1). EPA defines the term under 40 CFR 52.21(b)(18) as, "*emissions which would occur as a result of the construction or operation of a major stationary source… but do not come from the major stationary source…*"

Construction emissions are the only secondary emissions associated with the project. Donlin calculated and summarized their construction emissions in Section 2.2.2 of Appendix D to their 29 October, 2021 PSD permit application. Their calculations indicate that construction emissions are substantially smaller than the maximum project emissions for each PSD-triggered pollutant with an air quality standard or increment.

Donlin, therefore, did not provide a separate modeling analysis for their proposed construction activities since the project emissions are anticipated to offer a conservative representation of construction emissions from the project.

5.6.3. EU Inventory for the Increment Demonstrations

As discussed in the Background section of this report, Donlin's project will be located within a Class II area of the South Central Alaska Intrastate Air Quality Control Region. The major source baseline dates within this region are as follows:

- 8 February, 1988 for the annual NO_2 increment;
- 6 January, 1975 for the 24-hour and annual PM-10 increment;
- 20 October, 2010 for the 24-hour and annual PM-2.5 increment.

All of the project EUs are increment consuming for these pollutants/averaging periods. There are no Class II increments for the other PSD-triggered pollutants and averaging periods, i.e. GHG, one-hour NO_2, eight-hour O_3, one-hour CO, and eight-hour CO. Donlin included all applicable EUs in their increment demonstrations.

5.7. Emission Rates

The modeled emission rates are consistent with the emissions information provided throughout Donlin's 29 October, 2021 PSD application. The assumed emissions are generally related to the overall throughput of the mine, which is limited by the rated capacity of the gyratory crusher (GC) and the semi-autogenous grinding (SAG) mill. Donlin assumed the maximum capacity of the GC is 5,100 tph and the SAG mill 3,303 tph. The Department is, therefore, including these assumptions as enforceable terms and conditions to protect ambient air quality.

The Department is including enforceable terms and conditions limiting the total assumed capacity of the primary power plant generator sets, EUs 1 through 12, to protect ambient air quality. Donlin's application materials indicate that they propose to use Wärtsilä generator sets with a rated capacity of 17,076 kilowatts electric (kWe)[13] per unit. The total rated capacity of all twelve primary power plant generator sets is approximately 205 MW. The Department rounded this value to 210 MW in developing conditional language. Its approach mitigates the potential to reopen Donlin's permit if small changes in the installed rated capacity occur. The Department notes that its rounded value represents a two-percent increase from Donlin's assumed rated capacity. This percentage is within the margin of compliance for the modeled pollutants and averaging periods; see the results of Donlin's modeling Section 5.19 of this report for detail. The Department, therefore, finds that a two-percent increase in the assumed rated capacity of these EUs would not create potential violations of the AAAQS or increments.

[13] The rated capacity of these duel fuel units is indicated as 16,786 kWe when firing ULSD and 17,076 kWe when firing natural gas.

Donlin's modeled emission rates are consistent with those prescribed under Best Available Control Technology (BACT) requirements. The Department is, therefore, including compliance with the BACT emission rates for the modeled pollutants as enforceable terms and conditions to protect ambient air quality. Additional details regarding the modeled emission rates, along with several additional ambient air conditions related to the modeled emission rates, are provided below.

5.7.1. Use of Worst-Case Variables

The emission rates for dual fuel-fired EUs typically vary by fuel. Donlin provided the emission rates for both fuels, natural gas and ULSD, in Appendix B of their 29 October, 2021 PSD permit application. They selected the highest of the two emission rates for their modeling analysis.

Annual emissions from the mining and mobile source activities will change as the mine matures. Donlin estimated that the maximum annual emissions, by modeled pollutant, will occur during the following years within their proposed life of mine (LOM):

- Year 16 for PM-2.5;
- Year 19 for NOx and CO; and
- Year 20 for PM-10.

Donlin generally used the same LOM years in developing the worst-case one-hour, eight-hour and 24-hour *short-term* emission rates. Exceptions and additional factors used to develop the modeled annual and short-term emission rates are subsequently discussed.

5.7.2. Wärtsilä PM Emissions

Donlin used a PM emission rate of 0.29 grams per kilowatt hour (g/kW-hr) for the proposed Wärtsilä generator sets, EUs 1 through 12, in their modeling analysis. This value represents an emission rate for both filterable and condensable particulates while firing ULSD, and is based on vendor information form Wärtsilä. The Department finds that this assumption is sufficient to characterize the emissions from the proposed power generation units.

5.7.3. Blasting Emissions

EPA's *Compilation of Air Pollutant Emission Factors* (AP-42) contains an equation for deriving the PM emission factor for blasting. The horizontal area of the blast is the sole variable. Donlin's application materials indicate that the maximum blast area[14] during the proposed life of the mine is estimated at 120,000 ft^2. The Department is, therefore,

[14] The Department notes that other mining activities may be reduced during periods of blasting, especially large blasts, for safety or operational purposes. Donlin's approach of using the maximum blast area is anticipated to be conservative.

including a 120,000 ft^2 per blast assumption as enforceable terms and conditions to protect the PM-10 and PM-2.5 AAAQS and increments.

The emissions of NO_2 and CO from blasting are dependent on the quantity of blasting agent used. Donlin application materials indicate that the maximum annual consumption of blasting agent during the proposed life of the mine[15] is estimated at 60,000 tons per year (tpy). Similarly, the emissions from mining activities will be partially dependent on the amount of rock moved per year, which is related to the amount of blasting that will occur. The Department is, therefore, including Donlin's 60,000 tpy of blasting agent estimate as enforceable terms and conditions to protect ambient air quality.

5.7.4. Annual Operational Assumptions

Donlin's application materials indicate that the mine will operate continuously on an annual basis. They correspondingly assumed that the process, power plant, and ancillary sources will also operate continuously. However, Donlin assumed an annual operation of 500 hours per year (hr/yr) for each of EUs 29 through 37, which their application identifies as liquid fuel-fired black start and emergency use units. The Department is, therefore, including Donlin's 500 hr/yr assumption for these units as enforceable terms and conditions to protect the annual AAAQS and increments.

5.7.5. Wind-Blown Emissions

Donlin included the fugitive wind-blown emissions that may occur from exposed surfaces in their PM-10 and PM-2.5 modeling analyses. The exposed surfaces that could be subject to wind erosion include the haul roads, access roads, Tailings Beach, Waste Rock Facility, Short-term Stockpile, Long-term Stockpiles West and East, and Overburden Stockpile South. Wind is also a factor in determining the quantity of particulate emissions generated during the loading and unloading of aggregates. Wind erosion occurs when the wind speed over a freshly exposed surface exceeds the threshold friction velocity for the given material. The emissions are associated with intermittent wind gusts, but the emissions are conservatively assumed to occur for the entire hour for modeling purposes.

Donlin used the procedures for *industrial wind erosion* in Section 13.2.5 of AP-42 to estimate the particulate emissions from wind erosion. The procedure requires *fastest-mile* two-minute average wind speed data, which Donlin obtained by multiplying their hourly wind speed data by 1.24. Donlin previously justified their use of a 1.24 hour-to-fastest mile scaling factor in a 9 April, 2015 e-mail[16] provided in support of AQ0934CPT01. The Department continues to find this approach appropriate for the

[15] Donlin did not specify an assumed LOM year in which the most blasting agent would occur. Since other mining activity emissions are anticipated to be lower during the years of frequent blasting years, Donlin's use of the maximum NO_2 and CO blasting emissions, *ceteris paribus*, offers a conservative approach.

[16] E-mail from M. Rieser (Donlin) to A. Schuler (Department); *RE: Fastest Mile Wind Speed;* 9 April, 2015.

current project on a case-specific basis. A technical discussion and factual basis for Donlin's approach is provided in the Modeling Report for the aforementioned permit.

Donlin used the *overburden* classification in Table 13.2.5-5 of AP-42, and the associated 1.02 meter per second (m/s) threshold friction velocity to represent the material handled at all exposed stock piles, which includes the Tailings Beach and waste rock facility, as well as the road surfaces. The overburden classification provides a more conservative estimate of the wind-blown emissions from road surfaces than what would have occurred if the *roadbed material* classification is assumed. Donlin's use of the overburden classification for their stock piles is appropriate.

Donlin used the procedures for *aggregate handling and storage piles* in Section 13.2.4 of AP-42 to estimate the quantity of dust emissions generated from loading and unloading operations. This procedure requires the use of a mean wind speed, rather than the fastest-mile wind speed. Donlin used the hourly wind-speeds from their meteorological data for this calculation.

Donlin did not take credit in their PM modeling assessments for dust control at the Tailings Beach. However, they reduced the fugitive dust emissions from all unpaved roadways by 90-percent, based on the control methods[17] described in their Fugitive Dust Control Plan, provided as Appendix E to their 29 October, 2021 PSD permit application. The Department is, therefore, including enforceable terms and conditions requiring Donlin to comply with the methods described in their Fugitive Dust Control Plan to protect the PM AAAQS/increments.

5.7.6. Short-term Emissions Assumptions

The modeled emission rates for the short-term AAAQS and increments should generally reflect the maximum emissions allowed during the given averaging period. However, applicants may use the annual NOx emission rate for intermittently operated EUs when modeling the one-hour probabilistic NO_2 AAAQS.[18]

Donlin used the annual NOx emissions when modeling their one-hour NO_2 impacts from the black start and emergency generator-engines, EUs 29 through 37, since these units are intermittently operated. They used the maximum hourly emission rates for these EUs when modeling the short-term AAAQS and increments. They likewise used the maximum hourly emission rates for all other combustion-related EUs. The Department is including Donlin's 500 hr/yr assumption for the intermittently operated EUs as an ambient limit to protect the one-hour NO_2 AAAQS.

Donlin's application materials indicate that up to five blasts per day may occur. For the purposes of modeling, however, they assumed all five blasts would occur within the

[17] I.e. best practical methods (BPMs).

[18] EPA Memorandum from Tyler Fox to Regional Air Division Directors, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard;* March 1, 2011.

averaging period of the subject AAAQS or increment[19]. The Department is not imposing Donlin's assumed blasts per day as an ambient air condition since the frequency is relatively conservative, and the Department's limits on area per blast and quantity of blasting agent used, discussed in Section 5.7.3 of this report, is anticipated to be adequate to protect the AAAQS and increments.

Donlin assumed the process-related EUs will continuously handle 5,100 tph of material, which is the maximum throughput of the GC. They also assumed the refining-related EUs will continuously handle 3,303 tph of material, which is the maximum throughput of the SAG mill. Donlin also created an hourly emissions file for the fugitive emissions from the mine pit, Tailings Beach, and Waste Rock Facility. This allowed them to calculate and use hourly-specific wind-blown emission rates for these activities. They used the annual emission rates from the worst-case LOM years to estimate the short-term emission rates for the remaining mining and mobile source activities. The former approach is appropriate for the proposed project.

5.8. Point Source Parameters

In addition to the previously discussed emission rates, applicants must provide the stack height, diameter, location, base elevation, exhaust plume exit velocity, and exhaust temperature for each EU characterized as a point source.

The Department generally found Donlin's assumed exhaust parameters to be consistent with the vendor information or expectations for similarly sized EUs. Their assumed stack dimensions are also reasonable. For those EUs located within a building, Donlin generally used stack heights that are slightly taller than the surrounding structure. The stack heights for all other EUs are relatively short, and similar to the heights commonly found or expected for those types of EUs. The exceptions, or items that otherwise warrant additional discussion, are subsequently discussed.

5.8.1. General Discussion re Horizontal/Capped Stacks

Capped stacks and horizontal releases generally lead to higher impacts in the immediate near-field than the impacts from uncapped, vertical releases. EPA has, therefore, developed an option in AERMOD that revises the release parameters as described in the AERMOD User's Guide,[20] for any stack identified as horizontal (POINTHOR) or capped (POINTCAP).

Donlin assumed that the Wärtsilä generator sets have vertical, uncapped releases, and that all other point source releases are capped. They used the POINTCAP option to designate and characterize the capped stacks. The Department is including enforceable

[19] Illustratively, Donlin conservatively assumed all blasts would occur within an hour when modeling their one-hour impacts; within an eight-hour period when modeling the eight-hour impacts; and within a 24-hour period when modeling the 24-hour impacts.
[20] *User's Guide for the AMS/EPA Regulatory Model (AERMOD)*; EPA-454/B-16-011; December, 2016.

terms and conditions that require Donlin to construct vertical, uncapped releases on the Wärtsilä generator sets, EUs 1 through 12, to protect the AAAQS and increments.

5.8.2. Wärtsilä Exhaust Stacks Additional Discussion

Donlin has indicated that the twelve Wärtsilä generator sets, EUs 1 through 12, will be housed in two identical engine halls, each containing six generator sets. They further stated:

> *Each engine hall will consists of six stacks (one per engine) with identical release characteristics, clustered together in a configuration of two banks of three engines each. The six stacks in each cluster will be arranged tightly together, approximately one diameter apart.*

Identical plumes from stacks located this closely together would promptly merge upon release. Donlin, therefore, characterized each stack cluster as a single exhaust plume in their *merged* plume scenario. They used the actual release height, exhaust temperature, and exit velocity of a single stack for each merged plume, but an artificially large stack diameter so that the resulting volumetric exhaust flow would equal the total volumetric exhaust flow from all six stacks.

Donlin separately provided a *single* plume sensitivity analysis for this approach in support of AQ0934CPT01. The results of their analysis show that the AAAQS and increments would remain protected even when operating a single generator set in each hall. Under the single plume scenario, total emissions from the Wärtsilä engines would be approximately one-sixth of those in the merged plume scenario, though the exhaust plumes would also be less buoyant. Both scenarios provided proximate model results. Impacts from the single stack scenario did not exceed those from the merged plume scenario by more than 0.02 micrograms per cubic meter ($\mu g/m^3$).

The Department approved Donlin's merged plume approach 16 March, 2015[21] when it was proposed it in support of AQ0934CPT01. It continues to find this approach appropriate in the absence of meaningful revision to the proposed project following said approval.

Donlin assumed the Wärtsilä engine stacks will be 49 m tall. This assumption situates the emissions release above that of the tallest nearby structure,[22] though it is relatively tall for typical exhaust heights of reciprocating engines. The Department is, therefore, including Donlin's 49 m stack height assumption as enforceable permit terms and conditions to protect the AAAQS and increments. The Department notes that the 49 m assumption complies with the *Good Engineering Practice* stack height requirements in 18 AAC 50.045(e) – (f).

[21] E-mail from A. Schuler (Department) to M. Rieser (Donlin); *ADEC Okays Donlin's Merged Plume Proposal*; 16 March, 2015.

[22] The modeling files indicate that the Mill is the tallest structure near the Wärtsilä engine stacks. These files also indicate that the tallest part of the Mill is 34.6 m high. The resulting stack-height to building-height ratio is 1.4.

Donlin plans to recover waste heat from the Wärtsilä exhaust stacks to power a steam turbine in a combined cycle process. Donlin, therefore, used the post heat recovery exhaust temperature and exhaust flow rate, provided by the vendor, for their modeling analysis.

5.9. Open Pit Parameters

AERMOD has an open pit option for characterizing PM or gaseous emissions that occur below grade. Examples of where this option could be used include open pit mines and gravel quarries. Irregularly-shaped pit areas must be characterized by a rectangle of equal area when using the open pit option. Applicants who use this option must, therefore, provide AERMOD with the length of each side, the pit volume, and the average release height of the emissions activities within the pit, in addition to the pit location and base elevation. If warranted, the applicant may also provide an orientation angle of the pit in degrees from the North. If PM emissions are modeled, the applicant must also provide the same particle size information as needed to account for particle deposition.

Donlin used the OPENPIT option to characterize the gaseous and particulate emissions from drilling, material extraction, loading and unloading, dozing, and machinery activities that will occur within the open pit. This is a reasonable option for characterizing the below grade emission activities. Donlin appropriately assumed the same particle size used to account for particulate deposition; see Section 5.12.3 for detail.

Pit sizes change during the life of the mine. Donlin used the average pit volume and average base elevation between LOM years 16 and 20. LOM year 16 has the highest anticipated emissions of CO, NOx, and PM-2.5, and LOM year 20 has the highest anticipated emissions of PM-10. The former is a reasonable approach for modeling a constantly changing activity. Detail regarding Donlin's derivation of these values is presented in a 30 September, 2015 technical memorandum authored by Air Sciences, Inc. titled *Model Updates – Donlin Fugitive Source Parameters*.

Donlin used the weighted release height of the various activities characterized by the open pit algorithm, i.e., drilling, truck loading/unloading, equipment tailpipes, and dozing, in specifying a release height for the source. The resulting release height for LOM year 16 is 4.99 m and for LOM year 20 it is 4.85 m, which are reasonable values as proposed. Detail regarding Donlin's derivation of the open pir release height(s) may be found in the 10 September, 2015 technical memorandum authored by Air Sciences, Inc., *Donlin Fugitive Source Parameters*;[23] and a 17 August, 2015 letter from Donlin titled *Response to ADEC Comments on the Modeling Protocol from Donlin Gold LLC*.

5.10. Volume Source Parameters

The volume source option is frequently used to characterize fugitive emissions that have initial lateral and vertical spread near the point of release. Examples include the fugitive dust associated with construction activities or dirt roads, and wind-blown dust from storage piles.

[23] Donlin provided this technical memorandum as an attachment to a 10 September, 2015 e-mail from M. Rieser (Donlin) to A. Schuler (Department); *RE: Quick Questions re Donlin's u* Sensitivity Analysis*.

Applicants who characterize an EU or emissions activity as a volume source must provide AERMOD with the initial lateral and vertical dimensions of the volume, the release height of the emissions (volume center), and the source location and base elevation, in addition to the previously discussed emissions rate.

Donlin used the volume source option to characterize the fugitive emissions from blasting activities, haul roads, the waste rock storage facility, short- and long-term ore storage sites, the eastern long-term ore storage site, tailings dam, and overburden stockpile. The volume source option for these types of emissions activities is appropriate.

Donlin used the approach recommended by the Haul Road Workgroup of EPA/State/Local Modelers to develop the initial dimensions of each haul road segment.[24] Detail regarding Donlin's derivation of the haul road parameters may be found in their 17 August, 2015 letter, *Response to ADEC Comments on the Modeling Protocol from Donlin Gold LLC*. Donlin also used the Haul Road Workgroup guidance to develop the initial dimensions for the stockpile plumes since a significant portion of the stockpile emissions are associated with loading and unloading operations. Donlin used appropriate parameters for each volume source.

5.11. Area Source Parameters

The area source option is frequently used to characterize ground or low level releases with no thermal or momentum plume rise. It can be used in lieu of the volume source approach to characterize the fugitive dust emissions from dirt roads. It is typically used as an alternative approach to using volume sources to characterize haul roads, especially when characterizing long road segments or scenarios where receptors are within the area source footprint. Applicants who characterize an EU or emissions activity as an area source must provide AERMOD with the length and width of the area, the release height of the emissions, and the location and base elevation, in addition to the previously discussed emissions rate. If warranted, the user may also provide an orientation angle of the rectangle in degrees from the North, and the initial vertical dimension of the area source plume.

Donlin used the area source option to characterize the proposed access road and tailings storage facility. Using the area source option for the access road is appropriate given the long road segments. Using the area source option for the tailings storage facility is also appropriate based on the discussion provided by Air Sciences, Inc. in their 10 September, 2015 technical memorandum, *Donlin Fugitive Source Parameters*:

> *For the tailings storage facility (TAILS), a completely saturated tailings material (slurry) will be transferred through a pipeline (i.e., no truck dumping activity or material stockpiling; insignificant vertical dispersion), and the only emissions expected at this source are due to wind erosion of the exposed dry surfaces. Therefore, in the absence of any mechanical activity and vertical dispersion, a surface-based (zero release height) AREA source characterization was used.*

[24] Memorandum from R. Robinson, EPA Region 5 and M. Daye, EPA Region 7 to T. Fox, *Haul Road Workgroup Final Report;* 6 December, 2011.

Donlin used the approach recommended by the Haul Road Workgroup of EPA/State/Local Modelers to develop the release height and initial vertical dimension for the access road. Detail regarding Donlin's derivation of the access road parameters may be found in their 17 August, 2015 letter, *Response to ADEC Comments on the Modeling Protocol from Donlin Gold LLC*.

5.12. Pollutant Specific Considerations

The following pollutants warrant additional discussion.

5.12.1. Ambient NO_2 Modeling

The emissions of NOx from combustion sources include both nitric oxide (NO) and NO_2 constituents. After combustion gases exit a stack, additional NO_2 can be formed due to reactions within the atmosphere. Section 4.2.3.4 of the Guideline describes a three-tiered approach for estimating the ambient concentrations of NO_2 from this process, ranging from the simplest but very conservative assumption that all NO is converted to NO_2, to other more complex methods.

Donlin used the Ozone Limiting Method (OLM) to estimate their ambient NO_2 concentrations. OLM is an appropriate approach for estimating annual average NO_2 impacts under the EPA's Guideline.

5.12.1.1 In-Stack NO_2-to-NOx Ratio

The assumed NO_2-to-NOx in-stack ratio (ISR) is a variable that must be set for each NOx-emitting EU when modeling the NO_2 impacts with OLM. Source-specific data should be used to define this ratio when available. When source-specific data is not available, an ISR of 0.5 may be used without justification for the purposes of modeling the one-hour NO_2 impacts. According to EPA's 1 March, 2011 one-hour NO_2 modeling guidance, this value represents a reasonable upper bound based on the available in-stack data. EPA has not provided a similar 'default' ratio for the purposes of modeling the annual average NO_2 impacts.

Donlin performed a review of literature and stack test data to characterize the ISRs for their NOx-emitting EUs. These ratios are provided in their application materials. The Department maintains its findings regarding the appropriateness of these ISRs, *ceteris paribus*, as discussed in its 28 September, 2015 approval of Donlin's modeling protocol for AQ0934CPT01. The aforementioned ISRs are presented in Table 2.

Table 2. NO_2-to-NOx ISRs in AQ0934CPT02

EU Source Category	ISR
Blasting	0.036
Diesel Engines	0.11

EU Source Category	ISR
Diesel Engines w/Catalyzed Particulate Filters	0.22
Diesel Boilers	0.05
Natural Gas Boilers	0.10
Diesel Machinery	0.11

5.12.1.2 Ozone Data

OLM requires ambient ozone data in order to determine how much of the NO is converted to NO_2. Donlin used a temporally-varying data set that they derived from their pre-construction O_3 data. They developed a generic monthly-hour-of day O_3 profile that was used with their corresponding meteorological data. Donlin developed the former profile by taking the multi-year average of the maximum O_3 concentration for a given hour of day, i.e., hour 1 through 24, and within each month, i.e., January through December. The resulting O_3 profile is presented in Table 3-15 of Appendix D to their 29 October, 2021 PSD permit application. Donlin's approach in deriving a generic O_3 data set for NO_2 modeling is appropriate for the project. This approach also allows the data set to reflect significant seasonal variations that occur within Alaska.

5.12.1.3 AERMOD Settings

Donlin used the *OLMGROUP ALL* setting within AERMOD in their NO_2 modeling analysis. This setting is consistent with EPA's 1 March, 2011 one-hour NO_2 modeling guidance.

5.12.2. PM-2.5

PM-2.5 may be directly emitted from a source and is also formed through chemical reactions in the atmosphere, i.e. by secondary formation with other pollutants.[25] AERMOD is an acceptable model for performing a near-field analysis of the direct emissions, but EPA has not developed a near-field model that includes the necessary chemistry algorithms for estimating secondary impacts. EPA, therefore, recommends that applicants use existing technical information to assess their secondary PM-2.5 impacts by way of a "Tier 1" analysis[26]. The use of photochemical modeling to assess secondary impacts, i.e. a "Tier 2" analysis, may be appropriate as warranted.

Donlin's direct PM-2.5 and NOx precursor emissions exceed the respective PSD significant emission rates (SERs). In this situation, EPA recommends the use of air quality modeling to assess the direct impacts and states that one of the following options

[25] The emissions of NOx, SO_2, VOC, and Ozone are considered *precursor emissions*.
[26] EPA's tiered approach to assessing secondary PM-2.5 formation is described in Section 5.4 of the Guideline.

could be used for assessing the secondary impacts: a qualitative approach, a hybrid qualitative and quantitative approach that utilizes existing technical work, or a full quantitative photochemical grid modeling analysis. Of the three options for assessing secondary impacts, EPA stated that "*only a few situations would require explicit photochemical grid modeling*", i.e., the photochemical modeling approach would rarely be warranted.

Donlin used a qualitative approach to assess their secondary PM-2.5 impacts. This is an appropriate approach for stationary sources located in rural Alaska, or other areas with limited area-wide precursor emissions.

EPA has issued guidance regarding the characterization of secondary formation in various PSD scenarios.[27]. In its guidance, EPA notes that the maximum direct impacts and the maximum secondary impacts from a stationary source "*…are not likely well-correlated in time or space*", i.e., they will likely occur in different locations and at different times. This difference occurs because secondary PM-2.5 formation is a complex photochemical process that requires the presence of precursor pollutants in sufficient quantity for significant formation to occur. The conditions for this reaction process to meaningfully occur within the immediate project near-field, the location of maximum project impacts, is not anticipated to be likely.

EPA further stated that representative ambient monitoring data could be used to address the secondary formation that occurs from existing sources in a demonstration of the ambient standard. Donlin's pre-construction data used to represent the background concentration in their PM-2.5 AAAQS analysis is sufficient for requirement on a case-specific basis; see Section 5.17 for detail.

The Department notes that Donlin's qualitative PM-2.5 analysis indicates that the measured 24-hour and annual PM-2.5 concentrations are below the respective AAAQS. There appears to be no indication that secondary PM-2.5 formation from existing sources are causing or contributing to violations of the PM-2.5 AAAQS. Donlin also provided additional arguments that appropriately demonstrate that the PM-2.5 AAAQS will not be threatened by secondary PM-2.5 formation. Donlin's discussion of temporal and spatial factors of influence were similarly advanced in support of their PM-2.5 AAAQS and increment demonstrations. The resultant PM-2.5 modeling analyses illustrate a substantial margin of compliance with the 24-hour and annual PM-2.5 increments, as presented in Section 5.19, and that the minimal impacts from secondary formation at the maximum impact locations could be accommodated without potential violations of the Class II increments. Donlin did not include the effects of secondary PM-2.5 formation from area-wide sources in their PM-2.5 increment demonstrations since the regional sources are not increment consuming; see Section 3.6 for detail.

[27] *Guidance for $PM_{2.5}$ Permit Modeling* (EPA-454/B-14-001); May 2014.

5.12.3. Particle Deposition

Deposition refers to the natural settling of particles that occurs as a PM plume travels downwind. AERMOD has two algorithms for simulating this occurrence: *Method 1* and *Method 2*. The Method 1 approach may be applied under the *regulatory default* option of AERMOD, i.e. the use of Method 1 is allowed in a regulatory modeling analysis. The Method 2 approach is considered a *non-Guideline* method and, therefore, requires case-specific approval from the Department and EPA under the alternative modeling procedures of the Guideline. Donlin used the Method 1 deposition option within AERMOD to improve the accuracy of their estimated PM-10 and PM-2.5 concentrations.

The Method 1 algorithm requires data that reflects the particle size distribution for each activity with PM emissions. The user categorizes the emissions by particle size and then provides AERMOD the mass-mean aerodynamic particle diameter, mass fraction, and particle density for each category. Donlin calculated and categorized their particulate emissions as indicated in Tables 3-18 through 3-20 of Appendix D to their 29 October 2021 PSD permit application. Donlin's approach is appropriate to incorporate the effects of particle deposition in AQ0934CPT02.

5.13. Downwash

Downwash refers to the situation where local structures influence the plume from an exhaust stack. Downwash can occur when a stack height is less than a height derived by a procedure called *Good Engineering Practice* (GEP), which is defined in 18 AAC 50.990(42). It is a consideration when there are receptors relatively near the applicant's structures and exhaust stacks.

EPA developed the *Building Profile Input Program - PRIME* (BPIPPRM) program to determine which stacks could be influenced by nearby structures and to generate the cross-sectional profiles needed by AERMOD to determine the resulting downwash. Donlin used the current version of BPIPPRM, version 04274, to determine the building profiles needed by AERMOD.

Donlin included all of the modeled point sources in their downwash analysis. The Department used a proprietary 3-D visualization program to review their characterization of the exhaust stacks and structures. The characterization matches the figures provided in their permit application. Donlin appropriately accounted for downwash in their modeling analysis. BPIPPRM indicated that the modeled exhaust stacks are within the GEP stack height requirements.

5.14. Ambient Air Boundary

The AAAQS only apply within location of *ambient air*, which has been defined by EPA as "*…that portion of the atmosphere, external to buildings, to which the general public has* *access*." [28] Applicants may, therefore, exclude areas that they own or lease from an ambient demonstration if they employ "…*measures, which may include physical barriers, that are effective in precluding access to the land by the general public.*" [29] They conversely need to model that portion of their property/lease that has no such restriction, or where there is an easement or public right-of-way. Natural features, such as dense vegetation or topographical features, can provide adequate barriers to public access, although the adequacy of the given features must be evaluated on a case-specific basis.

Donlin identified a *Core Operating Area* (COA) to indicate the area(s) where public access will be precluded. They used the COA boundary as their ambient air boundary. The COA is identified in figures throughout Appendix D of their 29 October, 2021 PSD application and is discussed in their public access control plan (PACB), initially developed in March of 2017 and provided with their application materials.

Donlin asserts that their lease agreements grant them the legal authority to preclude access within the COA. They provided letters from both The Kuskokwim Corporation (TKC), and the Calista Corporation (Calista), that confirms they have the authority to preclude public access within the portion of the COA that is owned by the given corporation. They provided an abbreviated copy of the lease agreement with Lyman Resources in Alaska, Inc. (Lyman) on 19 January, 2016 confirming that they have exclusive access and use of the leased surface lands.

Donlin notes that there are 15 publicly recognized access easements or right-of-ways within the COA that they are attempting to reroute. They previously indicated that they petitioned the Alaska Department of Natural Resources, the Alaska Department of Transportation and Public Facilities, and the U.S. Bureau of Land Management to extinguish the easements within the COA. The Department is including enforceable terms and conditions to protect ambient air quality prohibiting operation until all easements or rights-of-way within the COA have been either extinguished or rerouted to areas outside the COA.

Donlin will use the methods described in their PACB to restrict public access within the COA. The methods vary by location, but may include fencing/gates, natural barriers, and surveillance by mine security. Donlin proposes to annually inform TKC and Calista shareholders on the access restrictions, as well as place warning signs at strategic locations. The Department is appending the PACB as a permit attachment and has included a condition requiring Donlin to restrict public access within the COA as described in the PACB.

[28] The term "ambient air" is defined in 40 CFR 50.1. The Alaska Legislature has also adopted the definition by reference in AS 46.14.990(2).

[29] EPA has authored multiple guidance documents regarding ambient air issues which may be found in their Modeling Clearinghouse Information Storage and Retrieval System at http://cfpub.epa.gov/oarweb/MCHISRS/. This language originates from the 2 December, 2019 Memorandum from EPA Administrator Andrew R. Wheeler to Regional Administrators: *Revised Policy on Exclusions from 'Ambient Air*.

5.15. Worker Housing

Donlin will need to house their workers on site due to the project's remote location. Worker housing areas must be treated as ambient air, except under the conditions described in the Department's *Ambient Air Quality Issues at Worker Housing* policy.[30] The conditions are:

1) the worker housing area is located within a secure or remote site;
2) the worker housing area is for official business/worker use only; and
3) the operator has a written policy stating that the on-site workers are on 24-hour call.

Donlin did not consider their worker housing area as a part of ambient air for the bases described in Section 3.4.2 of Appendix D to their 29 October, 2021 PSD permit application. The Department finds that their proposed worker housing meets the conditions listed in aforementioned policy.

5.16. Receptor Grid

Donlin used 50 m receptor grid spacing along their ambient air boundary. They placed additional receptors beyond the 50 m boundary grid as follows:

- every 100 m within the first 500 m of the 50 m grid; and
- every 500 m within the next km beyond the 100 m grid.

Following the model runs that observe the former receptor placement, Donlin confirmed their maximum impacts by performing a fine grid *hot spot* analysis for each pollutant and averaging period. The fine receptor grid consisted of receptors placed every 25 m within the general area of maximum impact for a given pollutant and averaging period. The hot spot analyses were found to offer proximate results. This approach both reduces uncertainty in the model-estimated values and demonstrates that the receptor grid has sufficient resolution to determine the maximum impacts.

5.17. Off-Site Impacts

The air quality impact from natural and regional sources, along with long-range transport from far away sources, must be accounted for in a cumulative AAAQS demonstration. The approach for incorporating these impacts must be evaluated on a case-specific basis for each type of assessment and for each pollutant, as applicable

Section 8.3 of the Guideline discusses how the off-site impacts could be incorporated for purposes of demonstrating compliance with an air quality standard. These impacts must be represented through either ambient monitoring data or through modeling. However, Section 8.3.3(b)(iii) notes, "*The number of nearby sources to be explicitly modeled in the air quality analysis is expected to be few except in unusual situations*." The language in this section further states that "*...sources that cause a significant concentration gradient in the vicinity*

[30] ADEC Policy and Procedure 04.02.108: *Worker Housing Aggregation and Modeling*, 5 May, 2021.

of the [applicant's source] *are not likely to be adequately characterized by the monitored data due to the high degree of variability of the source's impacts.*"

Donlin's project is located in a remote part of Alaska. There are no nearby stationary sources that would cause a significant concentration gradient within the project area. Illustratively, the nearest stationary source with an air quality control operating permit, the Bethel Power Plant, is approximately 250 km from the project area. This distance is beyond the 50 km range of AERMOD. Donlin, therefore, used their pre-construction monitoring data to represent the impact from all natural and anthropogenic off-site sources in their cumulative AAAQS analysis. This approach is both appropriate for the current project and consistent with the recommendations of EPA's Guideline.

There are various ways to add a background concentration to the modeled concentration in a cumulative AERMOD analysis. The typical practice is to manually sum the two values. Recent versions of AERMOD, however, include an option where the background concentration can be automatically added to the modeled concentration. This approach also allows applicants to observe temporarily varying background concentrations in their ambient demonstrations.

In their CO, PM-10, and PM-2.5 AAAQS demonstrations, Donlin added the maximum monitored concentration, in accordance with the form of the relevant AAAQS, to their modeled design concentration. They used temporarily varying background concentrations for their one-hour and annual NO_2 AAAQS demonstrations. Donlin did not include background concentrations in their cumulative *increment* assessments since there are no increment consuming sources within the project area.

The Department notes that Donlin derived temporally varying NO_2 background concentrations using the same approach as that for their O_3 profile; see Section 5.12.1.2 for detail. The resultant NO_2 concentrations are presented in Table 3-17 of Appendix D to their 29 October, 2021 PSD permit application. Donlin's use of the multi-year average of the maximum hour of day values within the month is consistent with EPA's one-hour NO_2 modeling guidance.

5.18. Design Concentrations

EPA allows applicants to use modeled concentrations that are consistent with the form of the given standard or increment. Donlin generally used the modeled concentrations that are consistent with this approach. They used a more conservative approach in their 24-hour PM-10 AAAQS and annual PM-2.5 AAAQS demonstrations. Donlin's design concentrations are summarized in Table 3.

Table 3. Modeled Design Concentrations in AQ0934CPT02

Pollutant	Avg. Period	AAAQS	Class II Increment
NO_2	One-hour	h8h	n/a

Pollutant	Avg. Period	AAAQS	Class II Increment
	Annual	HY	HY
PM-10	24-hour	h2h	h2h
	Annual	n/a	HY
PM-2.5	24-hour	h8h	h2h
	Annual	HY	HY
CO	One-hour	h2h	n/a
	Eight-hour	h2h	n/a

Table Notes:
h2h: high, second-high.
h8h: high, eighth-high. For purposes of 1-hour NO_2, the "h8h" is the five-year average of the high, eighth-high of the daily maximum 1-hr NO_2 concentrations. For purposes of 24-hour PM-2.5, the "h8h" is the five-year average of the high, eighth-high of the 24-hour PM-2.5 concentrations.
HY: highest annual average from any year.

5.19. Results and Discussion

The maximum NO_2, CO, PM-10, and PM-2.5 impacts from Donlin's AAAQS demonstration are presented in Table 4, along with the background concentrations, total impacts, and respective AAAQS. The total impact is less than the AAAQS for each pollutant and averaging period. Therefore, Donlin has demonstrated compliance with the NO_2, CO, PM-10 and PM-2.5 AAAQS.

Table 4. Maximum Impacts Compared to the AAAQS

Pollutant	Avg. Period	Max. Conc. (μg/m^3)	Bkgd. Conc. (μg/m^3)	Total Impact (μg/m^3)	AAAQS (μg/m^3)
NO_2	One-hour	119	See Notes	**119**	188
	Annual	11.6	See Notes	**11.6**	100
PM-2.5	24-hour	3.2	6.8	**10**	35
	Annual	0.6	2.3	**2.9**	12
PM-10	24-hour	21.6	14.1	**35.7**	150
CO	One-hour	10,582.1	686.9	**11,269**	40,000

Pollutant	Avg. Period	Max. Conc. (μg/m³)	Bkgd. Conc. (μg/m³)	Total Impact (μg/m³)	AAAQS (μg/m³)
	Eight-hour	2,679.1	457.9	**3,137**	10,000

Table Notes:
The NO_2 background concentration is included as a part of the AERMOD run.

The impacts from Donlin's NO_2, PM-10, and PM-2.5 Class II increment demonstrations are presented in Table 5, along with the respective Class II increment. The maximum impact is less than the applicable Class II increment for each pollutant and averaging period. Therefore, Donlin has demonstrated compliance with the NO_2, PM-10, and PM-2.5 Class II increments.

Table 5. Maximum Impacts Compared to the Class II Increments

Pollutant	Avg. Period	Max. Modeled Conc. (μg/m³)	Class II Increment (μg/m³)
NO_2	Annual	**4.5**	25
PM-2.5	24-hr	**7.5**	9
	Annual	**0.6**	4
PM-10	24-hr	**21.6**	30
	Annual	**4.3**	17

6. OZONE IMPACTS

As discussed in the Background section, VOC is a triggered PSD-pollutant for this project. There is no VOC AAAQS, but VOC and NOx emissions can form O_3, which does have an AAAQS. Donlin was, therefore, required to demonstrate compliance with the O_3 AAAQS, in accordance with 40 CFR 52.21(k).

O_3 is not usually emitted directly into the air. It is instead created in the atmosphere through chemical reactions involving sunlight and NOx/VOC emissions. It is inherently a regional pollutant, the result of chemical reactions between emissions from many NOx and VOC sources over a period of hours or days, and over a large area. EPA's Guideline does prescribe a recommended model for assessing the O_3 impact from an individual stationary source. Qualitative approaches are generally used to meet the 40 CFR 52.21(k) ambient demonstration requirement.

Donlin's project is located in an area that is designated as unclassifiable for all criteria pollutants, including O_3. There are no O_3 non-attainment areas in Alaska, including those areas with greater emissions of NOx and VOC. It is, therefore, unlikely that the NOx and VOC emissions from Donlin's project would cause or contribute to a violation of the O_3 AAAQS. Donlin provided a comparison of the project emissions to a larger selection of NOx and VOC emissions from Anchorage to support the former assumption. They then noted that, while reported Anchorage emissions are 4 to 10 times higher than those from their project, the ambient concentration still complies with the O_3 AAAQS. The Department finds that Donlin's O_3 demonstration is appropriate for AQ0934CPT02.

A summary of the emissions and concentrations that Donlin compared are presented in Table 6. Detail regarding their comparison is found in Section 3.13.3 of Appendix D to their 29 October, 2021 PSD permit application.

Table 6. DGP and Anchorage Area O_3 Comparison

Source	O_3 Precursor Emissions (tpy)			Monitored 8-hr O_3 Conc. (ppm)	8-hr O_3 AAAQS (ppm)
	NOx	VOC	Total		
DGP	3,258	1,279	4,537	0.051	0.070
Anchorage Area	12,298	14,428	26,726	0.045	

7. ADDITIONAL IMPACT ANALYSES

PSD applicants must assess the impact from the proposed project and associated growth on visibility, soils, and vegetation per 40 CFR 52.21(o). Donlin provided the additional impact analysis in Section 3.13.4 of Appendix D to their 29 October, 2021 PSD permit application. The Department's findings regarding their additional impact analysis are subsequently discussed.

7.1. Visibility Impacts

PSD applicants must assess whether the emissions from their stationary source, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility, such as visual range, contrast, or coloration, from that which would have existed under natural conditions. Visibility impacts can occur as visible plumes, i.e., *plume blight*, or in a general, area-wide reduction in visibility, also known as *regional haze*. Alaska does not have standards for plume blight. For Class I areas, the Federal Land Manager (FLM) provides the desired thresholds. There are no established thresholds for Class II areas. The typical tool for assessing plume blight is EPA's VISCREEN model.

The maximum range of VISCREEN is 50 km. When Class I areas lie beyond that range, as is the case for the current project, the Department recommends that applicants use the 50 km maximum range as the source to observer distance. This approach provides an upper bound of the potential plume blight impacts at more distant locations. In Donlin's case, using a 50 km source to observer distance provides very conservative results noting that Denali is approximately 315 km away. When running VISCREEN in an upper bound analysis, the 50 km range would also be used as the *nearest* source to boundary distance per page 24 of EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised)*.[31]

Since there are no Class II visibility thresholds, VISCREEN compares the visibility impacts to the Class I thresholds. VISCREEN provides results for impacts located <u>inside</u> a Class I area and for impacts located <u>outside</u> a Class I area. The latter is used in situations where there is an *integral vista*. In situations where there are no integral vistas, applicants only need to use the results for impacts located <u>inside</u> a Class I area. Alaska only has two integral vistas, both of which are associated with the Denali Class I area. Since the integral vistas are beyond the 50 km range of VISCREEN, the Department informed Donlin that they only needed to report the 'inside' results.

Donlin used the current version of VISCREEN, 13190, to estimate their worst-case plume blight. They appropriately assumed an ozone concentration of 40 parts per billion (ppb) and a background visual range of 250 km. They also appropriately excluded the fugitive and mobile emissions from the plume blight analysis since those emissions do not consist of coherent plumes. Donlin, therefore, observed the annual NOx and PM emissions from their point sources.

Donlin's initially used the default "Level 1" approach of assuming a constant 1.0 m/s wind speed and extremely stable 'F' class atmospheric conditions. This approach showed potential plume blight at 50 km. The Department notes that while Donlin appropriately followed standard practice in their Level 1 analysis, the results are very conservative and unlikely. Illustratively, winds would need to remain steady during the 87.5 hours it would take for a plume to travel from Donlin to Denali at 1.0 m/s.

Donlin's subsequently performed a "Level 2" analysis, which relies on more realistic plume travel times and uses site-specific meteorological conditions. EPA's *Workbook for Plume Visual Impact Screening and Analysis (Revised),* states: "*For the Level-2 screening analysis, we assume it is unlikely that steady-state plume conditions will persists for more than 12 hours.*" The wind speed would therefore need to be 8 m/s or greater for the plume to travel 315 km within 12 hours.

7.2. Soil and Vegetation Impacts

The ambient demonstration provided by applicants is typically adequate to show that their air emissions will not cause adverse impacts to soil or vegetation. EPA has established what they refer as *secondary* NAAQS in order to protect public welfare. The term 'welfare' is defined in Section 302(h) of the Clean Air Act to include "*effects on soils, water, crops, vegetation ...*" The AAAQS and primary NAAQS are identical for each of the modeled pollutants. However, the annual PM-2.5 secondary NAAQS (15 $\mu g/m^3$) is less stringent than the annual PM-2.5 primary NAAQS/AAAQS (12 $\mu g/m^3$). Therefore, a modeling analysis that demonstrates compliance with the AAAQS also demonstrates compliance with the

[31] *Workbook for Plume Visual Impact Screening and Analysis (Revised),* (EPA-454/R-92-023); October 1992.

secondary NAAQS.

Donlin demonstrated that they can comply with the AAAQS. Therefore, their ambient analysis indicates that they will not cause adverse impacts to soil or vegetation. The maximum cumulative impacts for the PSD-triggered pollutants with secondary NAAQS are presented in Table 7.

Table 7. Maximum Total Impacts Compared to the Secondary NAAQS

Pollutant	Avg. Period	Total Impact ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)
NO_2	Annual	**11.6**	100
PM-2.5	24-hour	**10**	35
	Annual	**2.9**	15
PM-10	24-hour	**35.7**	150

7.3. Associated Growth Analysis

40 CFR 52.21(o)(2) requires PSD applicants to provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source or modification. Donlin does not anticipate significant changes in these aspects of concern from their proposed project, which suggests there would be no associated impact on air quality. The Department finds Donlin's assessment reasonable.

8. CONCLUSION

The Department reviewed Donlin's permit application and concluded the following:

1. Donlin's ambient demonstration satisfies the ***Source Impact Analysis*** requirements of 40 CFR 52.21(k). Donlin demonstrated that the NOx, PM-10, PM-2.5, CO, and VOC emissions associated with operating the stationary source, within the restrictions listed in this report, will not cause or contribute to a violation of the NO_2, PM-10, PM-2.5, CO and O_3 AAAQS. They also demonstrated that the emissions will not cause or contribute to a violation of the NO_2, PM-10, and PM-2.5 Class II increments.

2. Donlin appropriately used the models and methods required under 40 CFR 52.21(l) ***Air Quality Models***.

3. Donlin conducted their modeling analysis in a manner consistent with the Guideline, as required under 18 AAC 50.215(b)(1).

4. Donlin pre-construction data satisfies the ***Preapplication Analysis*** requirements of 40 CFR 52.21(m)(1).

5. Donlin adequately addressed the ***Additional Impact Analysis*** provisions in 40 CFR 52.21(o).

The Department developed conditions in Construction Permit AQ0934CPT02 to ensure that Donlin complies with the modeled AAAQS and Class II increments. These conditions are *summarized* as follows:

To protect the NO_2, PM-10, PM-2.5, and CO AAAQS, and the NO_2, PM-10, and PM-2.5 Class II increments, the Permittee shall:

- Not operate under the Construction Permit until all easements or rights-of-way within the COA have been either extinguished or rerouted to areas outside the COA;
- Limit the throughput of the gyratory crusher to 5,100 tph and the semi-autogenous grinding mill to 3,303 tph;
- Limit the total rated capacity of the power plant generator sets, EUs 1 through 12, to no more than 210 MWe;
- Comply with the emissions standards for EUs subject to BACT;
- Use no more than 60,000 tpy of blasting agent at the stationary source;
- construct vertical, uncapped exhaust releases on the power plant generator sets, EUs 1 through 12; and
- construct exhaust releases for the power plant generator sets, EUs 1 through 12, that are at least 49 m in height.

To protect the PM-10 and PM-2.5 AAAQS and Class II increments, the Permittee shall:

- Limit the size of blasting area to no greater than 120,000 ft^2 per blast; and

- Comply with the Best Practical Methods (BPMs) described in the Fugitive Dust Control Plan

To protect the annually averaged NO_2 and PM-2.5 AAAQS, the annually averaged NO_2, PM-10, and PM-2.5 Class II increments, and the one-hour NO_2 AAAQS, the Permittee shall:

- Limit the emissions from intermittently used EUs 29 through 37 to no greater than 500 hr/yr.