Letter of Transmittal

To:	Permit Intake Clerk	**Date:**	July 23, 2015
Company:	Alaska Department of Environmental Conservation Air Permits Program	**Permit No.:**	AQ1086MSS02
Address:	619 E. Ship Creek, Suite 249		
	Anchorage , Alaska 99501		

Re: Eklutna Generation Station - Minor Air Quality Permit Application

FOR YOUR:

- [ ] Use
- [x] Approval
- [ ] Review/Comments
- [ ] Information
- [ ] Other:

SENT VIA:

- [ ] U.S. Postal Service
- [ ] Overnight
- [ ] Under Separate Cover
- [x] Hand-Carried (Courier)
- [ ] Picked Up

Date	QUANTITY	DESCRIPTION
July 23, 2015	1	Minor Air Quality Permit Application - Air Permit No. AQ1086MSS02

Remarks:

SLR is submitting this minor air quality permit application on behalf of MEA's Eklutna Generation Station. This application is to revise and rescind terms and conditions of Air Quality Control Minor Permit AQ1086MSS02.

ADEC AIR QUALITY
RECEIVED
JUL 23 2015
ANCHORAGE

cc: Gary Peers, MEA

By: Dani Baldwin, SLR Office # 907-563-2124

Matanuska Electric Association Incorporated

Eklutna Generation Station

Application to Revise Air Quality Control Minor Permit AQ1086MSS02

July 2015

Prepared by

SLR

MATANUSKA ELECTRIC ASSOCIATION
163 East Industrial Way
P.O. Box 2929
Palmer, Alaska 99645

July 23, 2015

Alaska Department of Environmental Conservation
Air Permits Program
Attention: Permit Intake Clerk
619 E. Ship Creek, Suite 249
Anchorage, Alaska 99501

Subject: **Eklutna Generation Station - Minor Air Quality Permit Application Revise and Rescind Terms and Conditions of Minor Air Permit Number AQ1086MSS02**

Dear Construction Permit Supervisor,

Matanuska Electric Association, Inc. (MEA) is submitting the enclosed minor air quality permit application under 18 Alaska Administrative Code (AAC) 50.508(6) to revise or rescind certain terms and conditions in Air Quality Control Minor Permit AQ1086MSS02 for the Eklutna Generation Station (EGS). The requested minor air permit changes are discussed in the attached Stationary Source Identification Form and associated attachments. A copy of Air Quality Control Minor Permit AQ1086MSS02 is provided in Attachment D.

MEA expects the Alaska Department of Environmental Conservation (ADEC) to charge an hourly permit administration fee for the processing the changes requested under 18 AAC 50.508(6), per 18 AAC 50.400(j).

If you have any questions regarding the enclosed permit application, please contact Dani Baldwin at 907-563-2124 or Traci Bradford at 907-761-9374.

Sincerely,

Gary W. Peers
Eklutna Generation Station Plant Manager

cc: Joe Griffith, MEA
Gary Kuhn, MEA
Tony Zellers, MEA
Traci Bradford, MEA
Dani Baldwin, SLR

Enclosure: Minor Air Quality Permit Application

Eklutna Generation Station
Application to Revise Air Quality Control Minor Permit AQ1086MSS02

July 2015

Prepared for

Matanuska Electric Association Incorporated
P.O. Box 2929
163 East Industrial Way
Palmer, Alaska 99645

Prepared by

SLR International Corporation
2700 Gambell Street, Suite 200
Anchorage, Alaska 99503
(907) 222-1112

Alaska Department of Environmental Conservation Air Quality Minor Permit Application	ADEC USE ONLY Receiving Date: ADEC Control Number AQ MSS :

STATIONARY SOURCE IDENTIFICATION FORM

Section 1 Stationary Source Information

Stationary Source Name: Eklutna Generation Station			SIC: 4911
Project Name (if different):	Stationary Source Contact: Traci Bradford		
Source Physical Address: 28705 Dena'ina Elders Road	City: Eklutna	State: AK	Zip: 99567
	Telephone: (907) 761-9374		
	E-Mail Address: traci.bradford@mea.coop		
UTM Coordinates (m) or Latitude/Longitude:	Northing:	Easting:	Zone:
	Latitude: 61 27' 34.5"	Longitude: 149 20' 33.9"	

Section 2 Legal Owner

Name: Matanuska Electric Association, Inc.		
Mailing Address: P.O. Box 2929, 163 E. Industrial Way		
City: Palmer	State: AK	Zip: 99645
Telephone #: (907) 761-9300		
E-Mail Address:		

Section 3 Operator *(if different from owner)*

Name:		
Mailing Address:		
City:	State:	Zip:
Telephone #:		
E-Mail Address:		

Section 4 Designated Agent *(for service of process)*

Name: Tony Zellers		
Mailing Address: P.O. Box 2929		
City Palmer	State:AK	Zip: 99645
Physical Address: 163 E. Industrial Way		
City: Palmer	State: AK	Zip: 99645
Telephone #: (907) 761-9358		
E-Mail Address: Tony.Zellers@mea.coop		

Section 5 Billing Contact Person *(if different from owner)*

Name: Traci Bradford		
Mailing Address: P.O. Box 2929, 163 E. Industrial Way		
City: Palmer	State: AK	Zip: 99645
Telephone #: (907) 761-9374		
E-Mail Address: traci.bradford@mea.coop		

Section 6 Application Contact

Name: Dani Baldwin, SLR International Corporation			
Mailing Address: 2700 Gambell Street, Suite 200	City: Anchorage	State: AK	Zip: 99503
	Telephone: (907) 563-2124		
	E-Mail Address: dbaldwin@slrconsulting.com		

Section 7 Desired Process Method *(Check only one – see 18 AAC 50.542(a) for process descriptions and restrictions)*

☐ Fast Track [18 AAC 50.542(b)]   ☒ Public Comment [18 AAC 50.542(d)]

Section 8 Project Description

Provide/attach a short narrative describing the project. Discuss the purpose for conducting this project, what emission units/activities will be added/modified under this project (i.e., project scope), and the project timeline. If the project is a modification to an existing stationary source, describe how this project will affect the existing process. Include any other discussion that may assist the Department in understanding your project or processing your application. Include a schedule of construction and the desired date for permit issuance.

If this application includes an Owner Requested Limit or a request to revise an existing permit term or condition, describe the intent of the limit, and provide sample language for the limit, and for monitoring, record keeping, and reporting for showing compliance with the limit.

Add additional pages if necessary.

This minor air permit application is being submitted by Matanuska Electric Association, Inc. (MEA) to revise or recind permit terms or conditions for Air Quality Control Minor Permit AQ1086MSS02 per 18 AAC 50.508(6).

Please see Attachment A.1 for the information required per 18 AAC 50.540(k).

MEA is requesting to revise or recind terms or conditions per 18 AAC 50.540(k)(2). Please see Attachment A.2 for the complete descriptions of MEA's requested revisions to minor air permit number AQ1086MSS02.

Section 9 Source Classification(s) *(Check all that apply)*

[18 AAC 50.502(b)]
☐ Asphalt Plant [≥ 5 ton per hour]
☐ Thermal Soil Remediation Unit [≥ 5 ton per hour]
☐ Rock Crusher [≥ 5 ton per hour]
☐ Incinerator(s) [total rated capacity ≥ 1000 lb/hour]
☐ Coal preparation plant
☐ Port of Anchorage Facility

If you checked any of the above, is (are) the emission unit(s) ☐ new, ☐ relocated*, or ☐ existing?

[18 AAC 50.502(c)(1)]
New or relocated* stationary source with potential emissions greater than:
☐ 40 tons per year (TPY) NOx
☐ 40 tons per year SO_2
☐ 15 tons per year PM-10
☐ 0.6 tons per year lead
☐ 100 tons per year CO in a nonattainment area

[18 AAC 50.502(c)(2)]
Construction or relocation* of a:
☐ Portable oil and gas operation
☐ 10 MMBtu/hr fuel burning equipment in a SO_2 special protection area

**Relocation does NOT include moving equipment from one place to another within your current stationary source boundary.*

Section 10 Modification Classification(s) *(Check all that apply)*

[18 AAC 50.502(c)(3)]
☐ NO_x Increase > 10 TPY [and existing PTE > 40 tons per year]
☐ SO_2 Increase > 10 TPY [and existing PTE > 40 tons per year]
☐ PM-10 Increase > 10 TPY [and existing PTE > 15 tons per year]
☐ CO Increase > 100 TPY [and existing PTE > 100 tons per year in a nonattainment area]

Basis for calculating modification:
☐ Projected actual emissions - baseline actual emissions
☐ New potential emissions - existing potential emissions

Section 11 Permit Action Request *(Check all that apply)*

[18 AAC 50.508]
☐ ~~Clean Unit designation~~ *(vacated by Court)*
☐ ~~Pollution Control Project designation~~ *(vacated by Court)*
☐ Establish Plantwide Applicability Limitation
☐ Establish emission reductions to offset nonattainment pollutant
☐ Owner Requested Limit*
☒ Revise or Rescind Title I Permit Conditions*
Permit Number: AQ1086MSS02 Date: 12/31/2013 Condition #: 1, 7, 7.1, 7.2, 7.3, 7.4, 7.4(a), 7.4(b), 7.4(c), 8.1, 8.1(a), 8.1(b), 8.1(c), 9, 9.1, 9.1(a), 9.1(b), 9.2, 9.3, 9.4, 9.4(a), 9.4(b), 9.5, 9.5(a), 9.5(b), 10.1, 10.2, 10.2(i), 11.1, 12, 13.2, 15.1(a), 15.2(a), 25.3

**Which to use? See* http://www.dec.state.ak.us/air/ap/docs/orlrtc.pdf

Section 12 Existing Permits and Limits

For an existing stationary source, do you have an existing:
(Check any that apply)
☒ Air quality permit Number(s)*:AQ1086MSS02
☐ Owner Requested Limit Number(s):
☐ Pre Approved (Emission) Limit Number(s)**:

** All valid construction, Title V, and minor permit numbers.*
***Optional. Please provide this number if possible.*
See http://www.state.ak.us/dec/air/ap/pals.htm

Section 13 Other Application Material

The information listed below must be included in your air quality control minor permit application. *Note: These must be attached in order for your application to be complete.*

If required to submit an analysis of ambient air quality under 18 AAC 50.540(c)(2), or if otherwise requested by the department:

☐ Attached are maps, plans, and/or aerial photographs as necessary to show the locations and distances of
- emissions units, buildings, emitting activities and boundaries of the associated with the stationary source, and
- nearby or adjacent residences, roads, other occupied structures and general topography within 15 kilometers.

(Indicate compass direction and scale on each.)

☐ Attached is a document (eg., spreadsheet) showing coordinates and elevations of each modeled unit, along with parameters necessary to characterize each unit for dispersion modeling.

☐ Attached is an electronic copy of all modeling files.

Section 14 Certification

This certification applies to the Air Quality Control Minor Permit Application for the Eklutna Generation Station (Stationary Source Name) submitted to the department on: July 2015.

Type of Application

☒ Initial Application

☐ Change to Initial Application

The application is **NOT** complete unless the certification of truth, accuracy, and completeness on this form bears the **signature of a responsible official** of the firm making the application. (18 AAC 50.205)

CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS

"Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."

Signature:	Date: July 23, 2015
Printed Name: Gary W. Peers	Title: Eklutna Generation Station Plant Manager

Section 15 Attachments

☒ Attachments Included. List attachments:

A - Requested Changes to Minor Permit AQ1086MSS02
B – Supporting Emission Calculations
C – Supporting Information for Requested Changes to Condition 8
D – Air Quality Control Minor Permit AQ1086MSS02

Section 16 Mailing Address

Submit the minor permit application to the Permit Intake Clerk in the department's Anchorage office. Submitting to a different office will delay processing. The mailing address and phone number for the Anchorage office is:

Permit Intake Clerk
Alaska Department of Environmental Conservation
Air Permit Program
619 E. Ship Creek, Suite 249
Anchorage, Alaska 99501
(907) 269-6881

Attachment A

Requested Changes to Minor Permit AQ1086MSS02

Attachment A

A.1 Request to Revise or Rescind Permit Terms or Conditions of Air Quality Control Permit AQ1086MSS02 per 18 AAC 50.540(k)

1. Please see Attachment D for a copy of the Title I permit required under 18 AAC 50.540(k)(1).
2. Please see Attachment A.2 for an explanation of the reasons the permit terms or conditions should be revised or rescinded per 18 AAC 50.540(k)(2).
3. Please see the following cited attachments for an explanation of the effects of revising or rescinding the permit terms or conditions as required under 18 AAC 50.540(k)(3).
    a. Please see Attachment B for supporting emissions calculations required under 18 AAC 50.540(k)(3)(A).
    b. Please see Attachment A.2 for the effect of the requested revisions on other permit terms and conditions required under 18 AAC 50.540(k)(3)(B).
    c. Provision 18 AAC 50.540(k)(3)(C) is not applicable because no change in permitted or actual emission rates is being requested for any modeled air pollutant. The result is the underlying ambient demonstration remains unchanged.
    d. The requested changes have no effect on the compliance monitoring under 18 AAC 50.540(k)(3)(D) other than as described in Attachment A.2.
4. The provision of 18 AAC 50.540(k)(4) is not applicable to the minor permit air application because the requested changes do not affect permit classification avoidance.

A.2 Requested Revisions and Explanation of Why the Permit Term or Condition Should be Revised or Rescinded for Air Quality Control Permit AQ1086MSS02

1. Condition 1, Table 1 – Please amend this table as follows to provide the make and model of the diesel storage tanks and the installation dates of certain emission units.

EU	Description	Make / Model	Rating	Fuel Type	Install Date
1	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015 ~~TBD~~
2	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015 ~~TBD~~
3	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015 ~~TBD~~
4	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015 ~~TBD~~
5	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015 ~~TBD~~
6	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	March 2015 ~~TBD~~
7	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015 ~~TBD~~
8	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015 ~~TBD~~
9	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015 ~~TBD~~
10	Generator Engine	Wartsila 18V50DF	17.1 MW	NG/ULSD	February 2015 ~~TBD~~
11	Firewater Pump	John Deere JU6H-UFADN0	197 hp	ULSD	October 2014 ~~TBD~~
12	Black Start Generator	Cummins 1000DQFAD	1,490 hp	ULSD	April 2015 ~~TBD~~
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	NG/ULSD	October 2014 ~~TBD~~
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMBtu/hr	NG/ULSD	October 2014 ~~TBD~~
15	Diesel Storage Tank	Rockford Corporation ~~To Be Determined (TBD)~~	436,842 ~~509,000~~ gal	Diesel	November 2014 ~~TBD~~
16	Diesel Storage Tank	Rockford Corporation ~~To Be Determined (TBD)~~	436,842 ~~509,000~~ gal	Diesel	November 2014 ~~TBD~~
17	Natural Gas Fuel Heater	ETI	7.0 MMBtu/hr	Natural Gas	TBD
18	Black Start Generator	Cummins 1000DQFAD	1,490 hp	ULSD	April 2015 ~~TBD~~

2. Conditions 7, 7.1, 7.2, and 7.3 – Please remove these conditions. The required performance test was conducted from February 3 through 5, 2015. The source test report was submitted to Alaska Department of Environmental Conservation (ADEC) on April 2, 2015. This one-time compliance obligation has been met, so these conditions are no longer needed to ensure compliance.

3. Condition 7.4, 7.4(a), 7.4(b), 7.4(c) – Please remove these conditions because the required performance test was conducted from February 3 through 5, 2015. The source test report was submitted to ADEC on April 2, 2015. The measured nitrogen oxides (NO_X), carbon monoxide (CO), coarse fraction respirable particulate matter (PM_{10}), and volatile organic compounds (VOC) emission rates did not exceed the rates listed in Condition 7.4, confirming the source-wide total potential emissions for the listed air pollutants are less than the threshold for Prevention of Significant Deterioration applicability. Specifically, the stationary source does not have potential annual emissions equal to or greater than 250 tons per year (tpy) for any of the listed air pollutants.

4. Condition 8 – Please amend this condition by removing the term “install” because this one-time compliance obligation has been met. The Selective Catalytic Reduction (SCR) and Catalytic Oxidizer (CATOX) control equipment has been installed downstream of each emission unit identification numbers (EU IDs) 1 through 10 according to the manufacturer’s instructions.

   Control Equipment: The Permittee shall ~~install,~~ operate~~,~~ and maintain a combined Selective Catalytic Reduction (SCR) and Catalytic Oxidizer (CATOX) control equipment downstream of each of EUs 1-10 according to manufacturer’s instructions and as follows:

5. Condition 8.1 - Please amend this condition as follows. The operating parameters listed in this condition are for the SCR and CATOX emission control system installed on EU IDs 1 through 10 while operating on natural gas.

   For the combined control equipment, <u>while operating on natural gas,</u> monitor and record hourly

6. Condition 8.1(a) - Please amend this condition as follows to reflect the actual ammonia reagent operating range for the SCR emission control system while still maintaining adequate assurance of compliance with the applicable emission rates. Data addressing the relationship between the actual ammonia injection rate and NO_X emission rate is provided in Attachment C to support this requested change. Please also see the request to remove Condition 7.4.

   (a) the rate of injection of the reducing aqueous ammonia reagent into the flue gas leaving the emission unit. The rate of injection of ammonia averaged over rolling three hours shall be no less than ~~6~~ <u>1.0</u> gallons per hour (gal/hr) and no more than 38.5 gal/hr, except during startup and shutdown~~, and should be high enough to achieve the emission rate listed in Condition 7.4~~.

7. Condition 8.1(b) - Please amend this condition as follows to clarify the flue gas temperature leaving the combined control equipment is to be averaged over a rolling three hour period to demonstrate compliance. This requested change reflects the operational stability of the emission control equipment.

   (b) the temperature of the flue gas leaving the combined control equipment. The temperature of the flue gas leaving the combined control equipment <u>averaged over rolling three hours</u> shall be no less than 536 °F and no more than 997 °F, except during startup and shutdown.

8. Condition 8.1(c) - Please amend this condition as follows to clarify the pressure drop across the combined control equipment is to be averaged over a rolling three hour period to demonstrate compliance. This change will also reflect the actual pressure drop operating range for the SCR and CATOX emission control system, while still maintaining adequate assurance of compliance with the applicable emission rates. Data supporting this range change request is provided in Attachment C.

   (c) pressure drop across the combined control equipment. The pressure drop <u>averaged over rolling three hours</u> shall be no less than ~~two~~ <u>1.5</u> inches of water and no more than ~~10~~ 9.5 inches of water, except during startup and shutdown.

9. Condition 9.1, 9.1(a), 9.1(b) – Please remove these conditions. The formaldehyde performance testing was conducted in February and March of 2015 using U.S. Environmental Protection Agency's (EPA) Method 323 and Method 320. The two source test reports were submitted to ADEC on April 2, 2015. This condition is no longer needed because this one-time compliance obligation has been met.

10. Condition 9.4, 9.4(a), 9.4(b) – Please remove these conditions. The formaldehyde emission rate was determined per Condition 9.1. The formaldehyde performance testing conducted on March 3 through 5, 2015, using EPA Method 323, provided formaldehyde emissions results for two Wartsila engines, EU IDs 8 and 9. The results demonstrate that formaldehyde emissions are well below the emission rate listed in Condition 9.4(a) when operating on natural gas. The most conservative (highest) emission rate determined based on the testing is 0.10 pounds per hour (lb/hr). The source test report was submitted to ADEC on April 2, 2015.

11. Condition 9, 9.2, 9.3, 9.5, 9.5(a), 9.5(b) – Please remove these conditions. The required formaldehyde performance testing was conducted on March 3 through 5, 2015, using EPA Method 323. The testing provided formaldehyde emissions results for two Wartsila engines, EU IDs 8 and 9, while operating on natural gas. The most conservative (highest) formaldehyde emission rate determined from the testing is 0.10 lb/hr. Based on the Method 323 results, potential formaldehyde emissions from the ten Wartsila 18V50DF engines, combined, are approximately 5 tpy while operating on natural gas. This potential emission is 50 percent of the 10 tpy single hazardous air pollutant (HAP) threshold for triggering the major hazardous air pollutant (HAP) source requirements under 18 Alaska Administrative Code (AAC) 50.316(a) and 40 Code of Federal Regulations (CFR) Part 63. As a result, the owner requested limit is no longer necessary to avoid a stationary source classification. The source test report for formaldehyde testing using Method 323 was submitted to ADEC on April 2, 2015.

12. Condition 10.1 – Please remove this condition. The required visible emission (VE) observations have been conducted on EU IDs 1 through 14 and 18, while operating exclusively on diesel. This one-time compliance obligation has been met, making this condition no longer necessary.

13. Condition 10.2 – Please remove this condition. The Method 9 VE test results have been submitted with the operating reports required under Condition 21 for EU IDs 1 through 14 and 18. This one-time compliance obligation has been met, making this condition no longer necessary.

14. Condition 10.2(i) – Please remove this condition. No VE observations exceeded the standards of Condition 10 for EU IDs 1 through 14 and 18, while operating exclusively on diesel. This one-time compliance obligation has been met, making this condition no longer necessary.

15. Condition 11.1 – Please remove this condition. The monitoring, recording, and reporting requirements have been completed on EU IDs 1 through 14 and 18, as described in Condition 10.1 and 10.2. This one-time compliance obligation has been met, making this condition no longer necessary.

16. Condition 12 – Please amend this condition as follows to reflect the standard operating permit condition language for sulfur compound emissions.

    Sulfur Compound Emissions: The Permittee shall not cause or allow sulfur compounds emissions, expressed as SO_2 from EUs 1 through 14, 17, and 18 to exceed 500 ppm~~v~~ averaged over three hours.

17. Condition 13.2 – Please remove this condition. As-built drawings of the release points of each exhaust stack for EU IDs 1 through 10 have been submitted in the operating report required under Condition 21. This one-time compliance obligation has been met, making this condition no longer necessary.

18. Condition 15.1(a) – Please revise this condition as follows to provide options for monitoring and recording the hydrogen sulfide (H_2S) content of the natural gas supplied to the facility.

    (a) Monitor and record the H_2S content of the natural gas monthly by obtaining and keeping a <u>current</u> certified letter, <u>valid purchase contract, tariff sheet, or transportation contract</u> from the supplier stipulating that the natural gas supplied during the month does not contain more than 20 ppmv H_2S.

19. Condition 15.2(a) – Please revise this condition as follows to provide options for the monitoring and recording of the sulfur content of the diesel supplied to the facility.

    (a) Monitor and record monthly the sulfur content of the diesel fuel burned by obtaining and keeping a <u>current</u> certified letter <u>or fuel receipts</u> from the diesel fuel supplier that the diesel fuel supplied during the month was ULSD.

20. Condition 25.3 – Please revise this condition for PM_{10} source testing. MEA requested the option to use EPA Method 5 and Method 202 as an alternative to the permit requirement of Method 201 or Method 201A and Method 202 due to the high exhaust temperature (between 536 and 997 degrees Fahrenheit) at the sampling location for the Wartsila 18V50DF generator engine, EU ID 10. Method 201A Section 8.6.1 states that Method 201A is not suitable for sources with stack temperatures exceeding 500 degrees Fahrenheit because of O-ring limitations and because the threads of the cyclone component may gall or seize. The use of the proposed alternative method was approved by ADEC in a letter dated January 6, 2015.

    Source testing for emissions of PM-10 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202. <u>For sources with stack temperatures exceeding 500 degrees Fahrenheit, source testing may be conducted in accordance with the procedures specified in 40 C.F.R. 60, Appendix A, Method 5 and 40 C.F.R. 51, Appendix M, Method 202.</u>

Attachment B

Supporting Emission Calculations

Table B-1. Matanuska Electric Association - Eklutna Generation Station
Prevention of Significant Deterioration (PSD) and Minor Air Quality Permit Applicability Summary

Pollutant	Potential Emissions		Change in Emissions	PSD Applicability Threshold 18 AAC 50.306[2]	PSD Applicability Threshold 18 AAC 50.306[3]	PSD Permit Required	Minor Permit Applicability Threshold	Permit Required per 18 AAC 50.502(c)
	Before Modification[1]	After Modification						
NO_X	188 tpy	188 tpy	0 tpy	40 tpy	250 tpy	No	10 tpy	No
CO	209 tpy	209 tpy	0 tpy	100 tpy	250 tpy	No	Not Applicable	No
PM	221 tpy	221 tpy	0 tpy	25 tpy	250 tpy	No	Not Applicable	No
PM_{10}	221 tpy	221 tpy	0 tpy	15 tpy	250 tpy	No	10 tpy	No
$PM_{2.5}$	221 tpy	221 tpy	0 tpy	10 tpy	250 tpy	No	Not Applicable	No
VOC	157 tpy	157 tpy	0 tpy	40 tpy	250 tpy	No	Not Applicable	No
SO_2	21 tpy	21 tpy	0 tpy	40 tpy	250 tpy	No	10 tpy	No
GHG CO_2e	719,024 tpy	719,578 tpy	554 tpy[5]	Not Applicable[6]	Not Applicable[6]	No	Not Applicable	No

Notes:

1. Potential criteria pollutant emissions are from Table A-1 of the Technical Analysis Report (TAR) for Minor Air Permit AQ1086MSS02.
2. If PSD applicability is triggered for a physical change that would constitute a major stationary source by itself, then PSD applicability is triggered for each pollutant for which there is a significant emissions increase, per 40 CFR 51.21(b)(23).
3. PSD applicability is triggered for a physical change that would constitute a major stationary source by itself, per 40 Code of Federal Regulations (CFR) 52.21(b)(1)(c).
4. PSD permit applicability analysis based on potential emissions prior to modification because 24 continuous months of actual emissions are not available.
5. Change in greenhouse gas (GHG) carbon dioxide equivalent (CO_2e) emissions are based on revised emission factors and global warming potential (GWP) factors.
6. As of June 23, 2014, PSD permit applicability is not triggered by GHG CO_2e emissions.
7. Emissions are based on maximum allowable operation and permit operating limits, where applicable.
8. Regulated air pollutant calculations are based on AP-42 emission factors, manufacturer data, and mass balances as shown in accompanying emission tables.
9. $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.
10. Tables B-13 through B-18 provide details on the Hazardous Air Pollutants (HAP) emissions calculations.

Table B-2. Matanuska Electric Association - Eklutna Generation Station
Emission Unit Inventory

Emission Unit			Fuel Type	Installation Date	Maximum Annual Operation	Maximum Capacity
ID	Description	Make/Model				
1	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	8,760 hr/yr	17.1 MW
2	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	8,760 hr/yr	17.1 MW
3	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	8,760 hr/yr	17.1 MW
4	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	8,760 hr/yr	17.1 MW
5	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	8,760 hr/yr	17.1 MW
6	Generator Engine	Wartsila 18V50DF	NG/Diesel	March 2015	8,760 hr/yr	17.1 MW
7	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	8,760 hr/yr	17.1 MW
8	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	8,760 hr/yr	17.1 MW
9	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	8,760 hr/yr	17.1 MW
10	Generator Engine	Wartsila 18V50DF	NG/Diesel	February 2015	8,760 hr/yr	17.1 MW
1-10 (combined)	Generator Engine	Wartsila 18V50DF	Diesel	N/A	1,680 hr/yr	17.1 MW (each)
11	Firewater Pump Engine	John Deere JU6H-UFADN0	Diesel	October 2014	500 hr/yr	197 hp
12	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015	1,000 hr/yr	1,490 hp
18	Black Start Generator Engine	Cummins 1000DQFAD	Diesel	April 2015		1,490 hp
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	8,760 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	NG	October 2014	8,760 hr/yr	15.75 MMBtu/hr
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014	1,000 hr/yr	15.75 MMBtu/hr
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	Diesel	October 2014		15.75 MMBtu/hr
15	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	436,842 gallons
16	Diesel Storage Tank	Rockford Corporation	Diesel	November 2014	8,760 hr/yr	436,842 gallons
17	Natural Gas Fuel Heater	ETI	NG	TBD	8,760 hr/yr	7.0 MMBtu/hr

Notes:

1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.

Table B-3. Matanuska Electric Association - Eklutna Generation Station
Nitrogen Oxide (NO_X) Emissions Calculations

Emission Unit			Fuel	Factor	NO_X Emission	Maximum Annual	Annual NO_X
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
2	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
3	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
4	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
5	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
6	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
7	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
8	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
9	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
10	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table D-12	19.95 lb/hr	1,680 hr/yr	16.8 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	2.7 g/hp-hr	500 hr/yr	0.3 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr	1,000 hr/yr	8.5 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	5.20 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.30 lb/hr	8,760 hr/yr	5.7 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	1.30 lb/hr	8,760 hr/yr	5.7 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.18 lb/hr	1,000 hr/yr	1.1 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	2.18 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	Manufacturer Data	0.78 lb/hr	8,760 hr/yr	3.4 tpy
						Total Existing Potential NO_X Emissions	188.3 tpy
						Total Potential NO_X Emissions After Modification	188.3 tpy

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.

Table B-4. Matanuska Electric Association - Eklutna Generation Station
Carbon Monoxide (CO) Emissions Calculations

Emission Unit			Fuel	Factor	CO Emission	Maximum Annual	Annual CO Emissions
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	
1	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
2	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
3	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
4	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
5	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
6	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
7	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
8	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
9	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
10	Generator Engine	17.1 MW	Natural Gas	See Table D-12	4.52 lb/hr	8,760 hr/yr	19.8 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Natural Gas	See Table D-12	6.78 lb/hr	1,680 hr/yr	5.7 tpy
11	Firewater Pump Engine	197 hp	Natural Gas	Manufacturer Data	0.9 g/hp-hr	500 hr/yr	0.1 tpy
12	Black Start Generator Engine	1,490 hp	Natural Gas	Manufacturer Data	0.66 g/hp-hr	1,000 hr/yr	1.1 tpy
18	Black Start Generator Engine	1,490 hp	Natural Gas	Manufacturer Data	0.66 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	Natural Gas	Manufacturer Data	0.58 lb/hr	8,760 hr/yr	2.5 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Natural Gas	Manufacturer Data	0.58 lb/hr	8,760 hr/yr	2.5 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Natural Gas	Manufacturer Data	0.56 lb/hr	1,000 hr/yr	0.3 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Natural Gas	Manufacturer Data	0.56 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Natural Gas	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Natural Gas			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	Natural Gas	Manufacturer Data	0.78 lb/hr	8,760 hr/yr	3.40 tpy
						Total Existing Potential CO Emissions	**209.4 tpy**
						Total Potential CO Emissions After Modification	**209.4 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.

Table B-5. Matanuska Electric Association - Eklutna Generation Station
Particulate Matter Less Than 10 Microns (PM_{10}) Emissions Calculations

Emission Unit			Fuel	Factor	PM_{10} Emission	Maximum Annual	Annual PM_{10}
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
2	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
3	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
4	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
5	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
6	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
7	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
8	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
9	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
10	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	4.89 lb/hr	8,760 hr/yr	21.4 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table D-12	10.92 lb/hr	1,680 hr/yr	9.2 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	500 hr/yr	0.0 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr	1,000 hr/yr	0.3 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.19 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.10 lb/hr	8,760 hr/yr	0.4 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.10 lb/hr	8,760 hr/yr	0.4 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.32 lb/hr	1,000 hr/yr	0.2 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.32 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	Manufacturer Data	0.008 lb/MMBtu	8,760 hr/yr	0.2 tpy
Total Existing Potential PM/PM_{10}/$PM_{2.5}$ Emissions							**220.9 tpy**
Total Potential PM/PM_{10}/$PM_{2.5}$ Emissions After Modification							**220.9 tpy**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.

Table B-6. Matanuska Electric Association - Eklutna Generation Station
Volatile Organic Compound (VOC) Emissions Calculations

Emission Unit			Fuel	Factor	VOC Emission	Maximum Annual	Annual VOC
ID	**Description**	**Rating/Capacity**	**Type**	**Reference**	**Factor**	**Operation**	**Emissions**
1	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
2	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
3	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
4	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
5	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
6	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
7	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
8	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
9	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
10	Generator Engine	17.1 MW	NG/Diesel	See Table D-12	3.43 lb/hr	8,760 hr/yr	15.0 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	See Table D-12	7.91 lb/hr	1,680 hr/yr	6.6 tpy
11	Firewater Pump Engine	197 hp	Diesel	Manufacturer Data	0.1 g/hp-hr	500 hr/yr	0.01 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr	1,000 hr/yr	0.2 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	Manufacturer Data	0.12 g/hp-hr		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.06 lb/hr	8,760 hr/yr	0.3 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	Manufacturer Data	0.06 lb/hr	8,760 hr/yr	0.3 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.06 lb/hr	1,000 hr/yr	0.03 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	Manufacturer Data	0.06 lb/hr		
15	Diesel Storage Tank	436,842 gallons	Diesel	TANKS 4.09d	Not Applicable	8,760 hr/yr	0.01 tpy
16	Diesel Storage Tank	436,842 gallons	Diesel	TANKS 4.09d		8,760 hr/yr	0.01 tpy
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	Manufacturer Data	0.48 lb/hr	8,760 hr/yr	2.1 tpy
						Total Existing Potential VOC Emissions	**156.9 tpy**
						Total Potential VOC Emissions After Modification	**156.9 tpy**

Notes:

1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.

Table B-7. Matanuska Electric Association - Eklutna Generation Station
Sulfur Dioxide (SO_2) Emissions Calculations

Emission Unit			Fuel Type	Factor Reference	SO_2 Emission Factor	Maximum Annual Operation	Annual SO_2 Emissions
ID	Description	Rating/Capacity					
1	Generator Engine	17.1 MW	NG/Diesel	Natural Gas	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmv H_2S		0.01 tpy
2	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmv H_2S		0.01 tpy
3	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmv H_2S		0.01 tpy
4	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmv H_2S		0.01 tpy
5	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmv H_2S		0.01 tpy
6	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmv H_2S		0.01 tpy
7	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmw S		0.01 tpy
8	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmw S		0.01 tpy
9	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmw S		0.01 tpy
10	Generator Engine	17.1 MW	NG/Diesel	NG	20 ppmv H_2S	8,760 hr/yr	2.0 tpy
				ULSD	15 ppmw S		0.01 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	ULSD	15 ppmw S	1,680 hr/yr	0.19 tpy
11	Firewater Pump Engine	197 hp	Diesel	ULSD	15 ppmw S	500 hr/yr	0.001 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S	1,000 hr/yr	0.01 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	ULSD	15 ppmw S		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	8,760 hr/yr	0.2 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	NG	20 ppmv H_2S	8,760 hr/yr	0.2 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S	1,000 hr/yr	0.01 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	ULSD	15 ppmw S		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable	Not Applicable	8,760 hr/yr	Not Applicable
16	Diesel Storage Tank	436,842 gallons	Diesel			8,760 hr/yr	
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	NG	20 ppmv H_2S	8,760 hr/yr	0.1 tpy
						Total Existing Potential SO_2 Emissions	**21.0 tpy**
						Total Potential SO_2 Emissions After Modification	**21.0 tpy**

Notes:

1. NG is natural gas. ULSD is ultra-low sulfur diesel.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.
4. Conversions and Vendor Data:

EU IDs 1-10 natural gas (with 1% diesel) heat rate:	8,153	kJ/kW-hr (natural gas)	EU IDs 13 and 14 fuel consumption rate:	15,752	scf/hr
EU IDs 1-10 natural gas (with 1% diesel) fuel consumption rate:	2	g/kW-hr (diesel)	EU IDs 13 and 14 fuel consumption rate:	110.31	gal/hr
EU IDs 1-10 diesel fuel consumption rate:	204	g/kW-hr	Natural gas heat content:	1,020	Btu/scf
EU ID 11 fuel consumption rate:	10.3	gal/hr	Standard Molar Volume:	359	scf/lb-mole
EU IDs 12 and 18 fuel consumption rate:	72.2	gal/hr	Diesel Heat Content:	138,000	Btu/gallon
EU ID 17 fuel consumption rate:	8,444	scf/hr	Diesel Density:	6.9	lb/gallon

5. Calculation is based on worst case scenario for EU IDs 1 through 10 when operating on diesel only.

Table B-8. Matanuska Electric Association - Eklutna Generation Station
Greenhouse Gas Emissions - Carbon Dioxide Equivalent (CO_2e) and Mass Emissions Calculations

Emission Unit			Fuel	Potential Greenhouse Gas Emissions (tpy)				
ID	Description	Rating/Capacity	Type	CO_2	CH_4	N_2O	GHG Mass	GHG CO_2e
1	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
2	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
3	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
4	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
5	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
6	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
7	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
8	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
9	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
10	Generator Engine	17.1 MW	NG/Diesel	67,672	1.30	0.135	67,674	67,745
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	21,067	0.85	0.171	21,068	21,139
11	Firewater Pump Engine	197 hp	Diesel	58	0.00	0.000	58	58
12	Black Start Generator Engine	1,490 hp	Diesel	812	0.03	0.007	812	815
18	Black Start Generator Engine	1,490 hp	Diesel					
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	7,609	0.14	0.015	7,609	7,617
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	7,609	0.14	0.015	7,609	7,617
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	1,284	0.05	0.010	1,284	1,288
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel					
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable				
16	Diesel Storage Tank	436,842 gallons	Diesel					
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	3,586	0.07	0.007	3,587	3,590
Total Existing Potential Greenhouse Gas Emissions							**718,258**	**719,024**
Total Potential Greenhouse Gas Emissions After Modification							**718,765**	**719,578**

Notes:
1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.

Table B-9. Matanuska Electric Association - Eklutna Generation Station
Carbon Dioxide (CO_2e) Emissions Calculations

Emission Unit			Fuel	Factor	CO_2 Emission	Maximum Annual	Annual CO_2
ID	**Description**	**Rating/Capacity**	**Type**	**Reference**	**Factor**	**Operation**	**Emissions**
1	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
2	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
3	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
4	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
5	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
6	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
7	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
8	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
9	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
10	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	67,703 tpy
				40 CFR 98, Table C-1	73.96 kg/MMBtu		1,292 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	1,680 hr/yr	21,067 tpy
11	Firewater Pump Engine	197 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	500 hr/yr	58 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	1,000 hr/yr	812 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	8,070 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	8,070 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu	1,000 hr/yr	1,284 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	40 CFR 98, Table C-1	73.96 kg/MMBtu		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable			
16	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable			
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	40 CFR 98, Table C-1	53.06 kg/MMBtu	8,760 hr/yr	3,586 tpy
						Total Existing Potential CO_2 Emissions	**718,242 tpy**
						Total Potential CO_2 Emissions After Modification	**718,749 tpy**

Notes:

1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.
4. Conversions and Vendor Data:

EU IDs 1-10 natural gas (with 1% diesel) heat rate:	8,153 kJ/kW-hr (natural gas)		EU IDs 12 and 18 fuel consumption rate:	72.2 gal/hr
EU IDs 1-10 natural gas (with 1% diesel) fuel consumption rate:	2 g/kW-hr (diesel)		Diesel Heat Content:	138,000 Btu/gallon
EU IDs 1-10 diesel fuel consumption rate:	204 g/kW-hr		Diesel Density:	6.9 lb/gallon
EU ID 11 fuel consumption rate:	10.3 gal/hr			

5. Calculation is based on worst case scenario for EU IDs 1 through 10 when operating on diesel only.

Table B-10. Matanuska Electric Association - Eklutna Generation Station
Methane (CH_4) Emissions Calculations

Emission Unit			Fuel	Factor	CH_4 Emission	Maximum Annual	Annual CH_4
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
2	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
3	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
4	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
5	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
6	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
7	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
8	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
9	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
10	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	1.28 tpy
				40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		0.05 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	40 CFR 98, Table C-2	3.0E-03 kg/MMBtu	1,680 hr/yr	0.85 tpy
11	Firewater Pump Engine	197 hp	Diesel	40 CFR 98, Table C-2	3.0E-03 kg/MMBtu	500 hr/yr	0.002 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	40 CFR 98, Table C-2	3.0E-03 kg/MMBtu	1,000 hr/yr	0.03 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	0.15 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	0.15 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	40 CFR 98, Table C-2	3.0E-03 kg/MMBtu	1,000 hr/yr	0.05 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	40 CFR 98, Table C-2	3.0E-03 kg/MMBtu		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable			
16	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable			
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	40 CFR 98, Table C-2	1.0E-03 kg/MMBtu	8,760 hr/yr	0.07 tpy
						Total Existing Potential CH_4 Emissions	**14.3 tpy**
						Total Potential CH_4 Emissions After Modification	**14.3 tpy**

Notes:

1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.
4. Conversions and Vendor Data:

EU IDs 1-10 natural gas (with 1% diesel) heat rate:	8,153 kJ/kW-hr (natural gas)	EU IDs 12 and 18 fuel consumption rate:	72.2 gal/hr
EU IDs 1-10 natural gas (with 1% diesel) fuel consumption rate:	2 g/kW-hr (diesel)	Diesel Heat Content:	138,000 Btu/gallon
EU IDs 1-10 diesel fuel consumption rate:	204 g/kW-hr	Diesel Density:	6.9 lb/gallon
EU ID 11 fuel consumption rate:	10.3 gal/hr		

5. Calculation is based on worst case scenario for EU IDs 1 through 10 when operating on diesel only.

Table B-11. Matanuska Electric Association - Eklutna Generation Station
Nitrous Oxide (N_2O) Emissions Calculations

Emission Unit			Fuel	Factor	N_2O Emission	Maximum Annual	Annual N_2O
ID	Description	Rating/Capacity	Type	Reference	Factor	Operation	Emissions
1	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
2	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
3	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
4	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
5	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
6	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
7	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
8	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
9	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
10	Generator Engine	17.1 MW	NG/Diesel	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.13 tpy
				40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		0.01 tpy
1-10 (combined)	Generator Engine	17.1 MW (each)	Diesel	40 CFR 98, Table C-2	6.0E-04 kg/MMBtu	1,680 hr/yr	0.17 tpy
11	Firewater Pump Engine	197 hp	Diesel	40 CFR 98, Table C-2	6.0E-04 kg/MMBtu	500 hr/yr	0.00 tpy
12	Black Start Generator Engine	1,490 hp	Diesel	40 CFR 98, Table C-2	6.0E-04 kg/MMBtu	1,000 hr/yr	0.01 tpy
18	Black Start Generator Engine	1,490 hp	Diesel	40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		
13	Auxiliary Boiler	15.75 MMBtu/hr	NG	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.02 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	NG	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.02 tpy
13	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	40 CFR 98, Table C-2	6.0E-04 kg/MMBtu	1,000 hr/yr	0.01 tpy
14	Auxiliary Boiler	15.75 MMBtu/hr	Diesel	40 CFR 98, Table C-2	6.0E-04 kg/MMBtu		
15	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable			
16	Diesel Storage Tank	436,842 gallons	Diesel	Not Applicable			
17	Natural Gas Fuel Heater	7.0 MMBtu/hr	NG	40 CFR 98, Table C-2	1.0E-04 kg/MMBtu	8,760 hr/yr	0.01 tpy
						Total Existing Potential N_2O Emissions	**1.6 tpy**
						Total Potential N_2O Emissions After Modification	**1.6 tpy**

Notes:

1. NG is natural gas.
2. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
3. Emissions were calculated using the worst case emission factors per hour when operating on either natural gas or diesel.
4. Conversions and Vendor Data:

EU IDs 1-10 natural gas (with 1% diesel) heat rate:	8,153 kJ/kW-hr (natural gas)	EU IDs 12 and 18 fuel consumption rate:	72.2 gal/hr
EU IDs 1-10 natural gas (with 1% diesel) fuel consumption rate:	2 g/kW-hr (diesel)	Diesel Heat Content:	138,000 Btu/gallon
EU IDs 1-10 diesel fuel consumption rate:	204 g/kW-hr	Diesel Density:	6.9 lb/gallon
EU ID 11 fuel consumption rate:	10.3 gal/hr		

5. Calculation is based on worst case scenario for EU IDs 1 through 10 when operating on diesel only.

Table B-12. Matanuska Electric Association - Eklutna Generation Station
Wartsila 18V50DF Manufacturer Data

Engine Operation[1,2]							
Percent Load	100	75	50		100	75	50
Engine Output, kW	17,076	12,974	8,494		17,076	12,974	8,494
Inlet Temperature, °C	15.6	15.6	15.6		26.7	26.7	26.7
Natural Gas[3]							
Natural Gas Fuel Consumption, kJ/kW-hr	7,258	7,562	8,153		7,258	7,562	8,153
Diesel Fuel Consumption, g/kW-hr	1.0	1.5	2.4		1.0	1.5	2.4
Flue Gas Temperature, °C ±15°C	399	435	443		397	433	441
Flue Gas Flow, kg/s ±5%	27.6	21.3	15.9		27.6	21.3	15.9
Flue Gas Flow, Nm^3/s (Dry)	19.7	15.2	11.3		19.6	15.1	11.3
Flue Gas Flow, Nm^3/s (Wet)[4]	21.9	16.9	12.6		21.8	16.8	12.6
Flue Gas Flow, m^3/s (Actual)	51.0	41.4	31.1		50.6	41.0	31.1
Flue Gas Velocity, m/s	25.7	20.9	15.8		24.8	20.9	15.8
NO_X, ppmvd @ 15% O_2	6	9	9		6	9	9
NO_X, g/kW-hr	0.08	0.12	0.13		0.08	0.12	0.13
NO_X, lb/hr	3.01	3.43	2.43		3.01	3.43	2.43
CO, ppmvd @ 15% O_2	15	15	15		15	15	15
CO, g/kW-hr	0.12	0.12	0.13		0.12	0.12	0.13
CO, lb/hr	4.52	3.43	2.43		4.52	3.43	2.43
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	20	25	30		20	25	30
PM_{10}, g/kW-hr	0.13	0.16	0.21		0.13	0.16	0.21
PM_{10}, lb/hr	4.89	4.58	3.93		4.89	4.58	3.93
VOC, ppmvd @ 15% O_2	20	25	25		20	25	25
VOC, g/kW-hr	0.09	0.12	0.13		0.09	0.12	0.13
VOC, lb/hr	3.39	3.43	2.43		3.39	3.43	2.43
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr [6]	0.23	NA	NA		0.23	NA	NA
Diesel							
Fuel Consumption, g/kW-hr	189	192	204		189	192	204
Flue Gas Temperature, °C ±15°C	355	355	389		368	368	402
Flue Gas Flow, kg/s ±5%	34.5	27.4	18.9		33.3	26.4	18.3
Flue Gas Flow, Nm^3/s (Dry)	25.1	20	13.8		24.1	19.2	13.3
Flue Gas Flow, Nm^3/s (Wet)[5]	26.4	21.1	14.5		25.4	20.2	14.0
Flue Gas Flow, m^3/s (Actual)	57.5	45.8	33.3		56.3	44.9	32.7
Flue Gas Velocity, m/s	30.1	23.9	17.4		29.6	23.5	17.1
NO_X, ppmvd @ 15% O_2	35	40	40		35	40	40
NO_X, g/kW-hr	0.53	0.61	0.64		0.53	0.61	0.64
NO_X, lb/hr	19.95	17.45	11.98		19.95	17.45	11.98
CO, ppmvd @ 15% O_2	20	20	20		20	20	20
CO, g/kW-hr	0.18	0.19	0.19		0.18	0.19	0.19
CO, lb/hr	6.78	5.43	3.56		6.78	5.43	3.56
PM_{10}, mg/Nm^3 @ 15% O_2 (Dry)	40	50	60		40	50	60
PM_{10}, g/kW-hr	0.29	0.37	0.46		0.29	0.37	0.46
PM_{10}, lb/hr	10.92	10.58	8.61		10.92	10.58	8.61
VOC, ppmvd @ 15% O_2	40	40	40		40	40	40
VOC, g/kW-hr	0.21	0.21	0.22		0.21	0.21	0.22
VOC, lb/hr	7.91	6.01	4.12		7.91	6.01	4.12
CH_2O, ppmvd @ 15% O_2	0.70	NA	NA		0.70	NA	NA
CH_2O, lb/hr [7]	0.28	NA	NA		0.28	NA	NA

Notes:
1. Values at 25 percent load are not provided, because this load is normally below manufacturer guaranteed stable operation.
2. Emission rates represent source test data measured after Selective Catalytic Reduction (SCR) and Catalytic Oxidation (CATOX) emission control systems. SCR control efficiency estimated at 93 to 94 percent. CATOX control efficiency estimated at 93 to 94 percent for carbon monoxide and 70 percent for volatile organic compounds.
3. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
4. Normal flue gas flow for natural gas combustion assumes 10 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
5. Normal flue gas flow for diesel combustion assumes 5 percent moisture content. Actual pressure is conservatively estimated as standard pressure.
6. Based on F_d factor of 8,710 for natural gas (40 CFR 60, Appendix A, Method 19).
7. Based on F_d factor of 9,190 for diesel (40 CFR 60, Appendix A, Method 19).

Table B-13. Matanuska Electric Association - Eklutna Generation Station
Summary of Estimated Potential Hazardous Air Pollutants (HAP) Emissions

Hazardous Air Pollutant	Storage Tanks[2]	Natural Gas Engines[3]	Diesel Engines <600 hp	Diesel Engines >600 hp	Natural Gas Heater and Boiler	Diesel Boilers	Total HAP Emissions[1]
Acetaldehyde	----	0.90	2.73E-04	5.05E-03	----	----	**0.91**
Acrolein	----	0.07	3.29E-05	1.58E-03	----	----	**0.07**
Benzene	----	0.36	3.32E-04	1.55E-01	3.67E-04	1.18E-05	**0.52**
1,3-Butadiene	----	0.64	1.39E-05	----	----	----	**0.64**
Biphenyl	----	0.37	----	----	----	----	**0.37**
Carbon tetrachloride	----	0.06	----	----	----	----	**0.06**
Chlorobenzene	----	0.05	----	----	----	----	**0.05**
Chloroform	----	0.05	----	----	----	----	**0.05**
1,4-Dichlorobenzene(p)	----	----	----	----	2.10E-04	----	**0.00**
1,3-Dichloropropene	----	0.05	----	----	----	----	**0.05**
Ethyl benzene	----	0.12	----	----	----	3.51E-06	**0.12**
Ethylene dibromide (Dibromoethane)	----	0.08	----	----	----	----	**0.08**
Formaldehyde	----	4.38	4.19E-04	2.35E-01	1.32E-02	1.82E-03	**4.63**
N-Hexane	----	1.93	----	----	3.15E-01	----	**2.24**
Methanol	----	4.34	----	----	----	----	**4.34**
Methyl chloroform (1,1,1-Trichloroethane)	----	----	----	----	----	1.30E-05	**0.00**
Methylene chloride(Dichloromethane)	----	0.03	----	----	----	----	**0.03**
Phenol	----	0.04	----	----	----	----	**0.04**
Polycyclic Organic Matter (POM)	----	0.10	5.97E-05	4.24E-02	1.22E-04	1.82E-04	**0.15**
Styrene	----	0.04	----	----	----	----	**0.04**
1,1,2,2-Tetrachloroethane	----	0.07	----	----	----	----	**0.07**
Toluene	----	0.44	1.45E-04	5.63E-02	5.95E-04	3.42E-04	**0.50**
1,1,2-Trichloroethane	----	0.06	----	----	----	1.30E-05	**0.06**
2,2,4-Trimethylpentane	----	0.43	----	----	----	----	**0.43**
Vinyl chloride	----	0.03	----	----	----	----	**0.03**
Xylenes	----	1.17	1.01E-04	3.86E-02	----	6.01E-06	**1.20**
Arsenic Compounds	----	----	----	----	3.50E-05	3.04E-05	**6.54E-05**
Beryllium Compounds	----	----	----	----	2.10E-06	2.28E-05	**2.49E-05**
Cadmium Compounds	----	----	----	----	1.92E-04	2.28E-05	**2.15E-04**
Chromium Compounds	----	----	----	----	2.45E-04	2.28E-05	**2.68E-04**
Cobalt Compounds	----	----	----	----	1.47E-05	----	**1.47E-05**
Lead Compounds	----	----	----	----	----	6.85E-05	**6.85E-05**
Manganese Compounds	----	----	----	----	6.65E-05	4.57E-05	**1.12E-04**
Mercury Compounds	----	----	----	----	4.55E-05	2.28E-05	**6.83E-05**
Nickel Compounds	----	----	----	----	3.67E-04	2.28E-05	**3.90E-04**
Selenium Compounds	----	----	----	----	4.20E-06	1.14E-04	**1.18E-04**
Total HAPs - Maximum Individual HAP	**0.00**	**4.38**	**0.0004**	**0.23**	**0.31**	**0.002**	**4.63**
Total HAP Emissions Before Modification	**0.00**	**21.03**	**0.001**	**0.53**	**0.33**	**0.003**	**21.90**
Total HAP Emissions After Modification	**0.00**	**15.81**	**0.001**	**0.53**	**0.33**	**0.003**	**16.68**

Notes:
1. See individual emissions unit category emissions calculations for details on methodology and assumptions in the electronic copy.
2. HAPs from the storage tanks are negligible.
3. Formaldehyde emissions are based on source testing conducted using Method 323. The source test report was submitted to ADEC on April 2, 2015.

Table B-14. Matanuska Electric Association - Eklutna Generation Station
Estimated Potential HAP Emissions - Lean Burn Natural Gas Engines

Maximum Total Heat Input:	**11,575,600 MMBtu/yr[1]**
Maximum Total Fuel Consumption:	**11,349 MMscf/yr**

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations			
CAS No.	**Chemical Name**	**Emission Factor**	**Factor Reference[2]**	**Estimated Uncontrolled Emissions**	**Estimated Controlled Emissions[3]**
75-07-0	Acetaldehyde	5.29E-01 lb/MMscf	CATEF Database	3.00 tpy	0.90 tpy
107-02-8	Acrolein	3.92E-02 lb/MMscf	CATEF Database	0.22 tpy	0.07 tpy
71-43-2	Benzene	2.12E-01 lb/MMscf	CATEF Database	1.20 tpy	0.36 tpy
92524	Biphenyl	2.12E-04 lb/MMBtu	Table 3.2-2, AP-42	1.23 tpy	0.37 tpy
106-99-0	1,3-Butadiene	3.78E-01 lb/MMscf	CATEF Database	2.14 tpy	0.64 tpy
56235	Carbon tetrachloride	3.67E-05 lb/MMBtu	Table 3.2-2, AP-42	0.21 tpy	0.06 tpy
108907	Chlorobenzene	3.04E-05 lb/MMBtu	Table 3.2-2, AP-42	0.18 tpy	0.05 tpy
67663	Chloroform	2.85E-05 lb/MMBtu	Table 3.2-2, AP-42	0.16 tpy	0.05 tpy
542756	1,3-Dichloropropene	2.64E-05 lb/MMBtu	Table 3.2-2, AP-42	0.15 tpy	0.05 tpy
100414	Ethyl benzene	7.00E-02 lb/MMscf	CATEF Database	0.40 tpy	0.12 tpy
1006934	Ethylene dibromide (Dibromoethane)	4.43E-05 lb/MMBtu	Table 3.2-2, AP-42	0.26 tpy	0.08 tpy
5-00-0	Formaldehyde	0.10 lb/hr	See Note 4.	NA	4.38 tpy
110543	N-Hexane	1.11E-03 lb/MMBtu	Table 3.2-2, AP-42	6.42 tpy	1.93 tpy
67561	Methanol	2.50E-03 lb/MMBtu	Table 3.2-2, AP-42	14.47 tpy	4.34 tpy
75092	Methylene chloride(Dichloromethane)	2.00E-05 lb/MMBtu	Table 3.2-2, AP-42	0.12 tpy	0.03 tpy
108952	Phenol	2.40E-05 lb/MMBtu	Table 3.2-2, AP-42	0.14 tpy	0.04 tpy
100425	Styrene	2.36E-05 lb/MMBtu	Table 3.2-2, AP-42	0.14 tpy	0.04 tpy
79345	1,1,2,2-Tetrachloroethane	4.00E-05 lb/MMBtu	Table 3.2-2, AP-42	0.23 tpy	0.07 tpy
108-88-3	Toluene	2.59E-01 lb/MMscf	CATEF Database	1.47 tpy	0.44 tpy
79005	1,1,2-Trichloroethane	3.18E-05 lb/MMBtu	Table 3.2-2, AP-42	0.18 tpy	0.06 tpy
540841	2,2,4-Trimethylpentane	2.50E-04 lb/MMBtu	Table 3.2-2, AP-42	1.45 tpy	0.43 tpy
75014	Vinyl chloride	1.49E-05 lb/MMBtu	Table 3.2-2, AP-42	0.09 tpy	0.03 tpy
1330-20-7	Xylenes (isomers and mixture)	6.85E-01 lb/MMscf	CATEF Database	3.89 tpy	1.17 tpy
N/A	Polycyclic Organic Matter (POM)	6.04E-05 lb/MMBtu		0.35 tpy	0.10 tpy
	Polycyclic aromatic compounds(PAH)	6.04E-05 lb/MMBtu			
	Acenaphthene	1.56E-04 lb/MMscf	CATEF Database		
	Acenaphthylene	5.16E-04 lb/MMscf	CATEF Database		
	Benzo(b)fluoranthene	1.66E-07 lb/MMBtu	Table 3.2-2, AP-42		
	Benzo(k)fluoranthene	8.54E-06 lb/MMscf	CATEF Database		
	Benzo(e)pyrene	4.15E-07 lb/MMBtu	Table 3.2-2, AP-42		
	Benzo(g,h,i)perylene	4.14E-07 lb/MMBtu	Table 3.2-2, AP-42		
	Chrysene	1.58E-05 lb/MMscf	CATEF Database		
	Dibenz(a,h)anthracene	2.52E-06 lb/MMscf	CATEF Database		
	Fluoranthene	2.99E-04 lb/MMscf	CATEF Database		
	Fluorene	3.49E-04 lb/MMscf	CATEF Database		
	Ideno(1,2,3-cd)pyrene	8.06E-06 lb/MMscf	CATEF Database		
	2-Methylnaphthalene	3.32E-05 lb/MMBtu	Table 3.2-2, AP-42		
91-20-3	Naphthalene	2.34E-02 lb/MMscf	CATEF Database		
	Phenanathrene	1.80E-03 lb/MMscf	CATEF Database		
	Pyrene	1.91E-04 lb/MMscf	CATEF Database		
			Total Potential HAP Emissions:	**38.10 tpy**	**15.81 tpy**

Notes:

1. Total heat consumption based on full-time or permit-limited operation for the following:

17.1 MW Generator Engines - Wartsila		132.1 MMBtu/hr, each	
Potential Heat Consumption:	EU IDs 1-10		11,575,600 MMBtu/yr
Total Potential Heat Input:			**11,575,600 MMBtu/yr**
Vendor engine heat rate for natural gas use:			8,153 kJ/kW-hr[6]
Annual fuel use converted to MMBtu/yr based on a natural gas fuel heat content:			1,020 Btu/scf

2. References: AP-42, Table 3.2-2 and median values from California Air Toxics Emission Factors (CATEF) database (4S/Lean/>650Hp).
3. HAP emission control efficiency estimated at 70 percent for catalytic oxidation.
4. Formaldehyde emissions are based on source testing conducted using Method 323. The source test report was submitted to ADEC on April 2, 2015.
5. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
6. See Table B-12 for fuel consumption rates from vendor data.

Table B-15. Matanuska Electric Association - Eklutna Generation Station
Estimated Potential HAP Emissions - Diesel Engines Less Than 600 Horsepower

Maximum Total Heat Input: 711 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
75070	Acetaldehyde	7.67E-04 lb/MMBtu	2.73E-04 tpy
107028	Acrolein	9.25E-05 lb/MMBtu	3.29E-05 tpy
71432	Benzene	9.33E-04 lb/MMBtu	3.32E-04 tpy
106990	1,3-Butadiene	3.91E-05 lb/MMBtu	1.39E-05 tpy
5000	Formaldehyde	1.18E-03 lb/MMBtu	4.19E-04 tpy
108883	Toluene	4.09E-04 lb/MMBtu	1.45E-04 tpy
1330207	Xylenes (isomers and mixture)	2.85E-04 lb/MMBtu	1.01E-04 tpy
N/A	Polycyclic Organic Matter (POM)	1.68E-04 lb/MMBtu	5.97E-05 tpy
	Polycyclic aromatic compounds(PAH)		
91203	Naphthalene	8.48E-05 lb/MMBtu	3.01E-05 tpy
	Acenaphthylene	5.06E-06 lb/MMBtu	1.80E-06 tpy
	Acenaphthene	1.42E-06 lb/MMBtu	5.05E-07 tpy
	Fluorene	2.92E-05 lb/MMBtu	1.04E-05 tpy
	Phenanthrene	2.94E-05 lb/MMBtu	1.04E-05 tpy
	Anthracene	1.87E-06 lb/MMBtu	6.65E-07 tpy
	Fluoranthene	7.61E-06 lb/MMBtu	2.70E-06 tpy
	Pyrene	4.78E-06 lb/MMBtu	1.70E-06 tpy
	Benzo(a)anthracene	1.68E-06 lb/MMBtu	5.97E-07 tpy
	Chrysene	3.53E-07 lb/MMBtu	1.25E-07 tpy
	Benzo(b)fluoranthene	9.91E-08 lb/MMBtu	3.52E-08 tpy
	Benzo(k)fluoranthene	1.55E-07 lb/MMBtu	5.51E-08 tpy
	Benzo(a)pyrene	1.88E-07 lb/MMBtu	6.68E-08 tpy
	Indeno(1,2,3-cd)pyrene	3.75E-07 lb/MMBtu	1.33E-07 tpy
	Dibenz(a,h)anthracene	5.83E-07 lb/MMBtu	2.07E-07 tpy
	Benzo(g,h,l)perylene	4.89E-07 lb/MMBtu	1.74E-07 tpy
		Total Potential HAP Emissions:	**0.001 tpy**

Notes:

1. Total fuel consumption based on full-time operation for the following:

197 hp Firewater Pump Engine - John Deere JU6H-UFADN0

Potential Heat Consumption:	EU ID 11	710.7	MMBtu/yr at maximum allowed operation of 500 hr/yr
Total Potential Heat Input:		**710.7**	**MMBtu/yr**
Vendor engine fuel consumption rate:		10.3	gal/hr
Annual fuel use converted to MMBtu/yr based on a diesel fuel heat content:		138,000	Btu/gal

2. References: AP-42, Table 3.3-2.
3. See Attachment C for fuel consumption rates from vendor data.

Table B-16. Matanuska Electric Association - Eklutna Generation Station
Estimated Potential HAP Emissions - Diesel Engines Greater Than 600 Horsepower

Maximum Total Heat Input: 400,467 MMBtu/yr [1]

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
75-07-0	Acetaldehyde	2.52E-05 lb/MMBtu	5.05E-03 tpy
107-02-8	Acrolein	7.88E-06 lb/MMBtu	1.58E-03 tpy
71-43-2	Benzene	7.76E-04 lb/MMBtu	1.55E-01 tpy
5-00-0	Formaldehyde	7.89E-05 lb/MMBtu[3]	3.93E-04 tpy
5-00-0	Formaldehyde	0.28 lb/hr[4]	0.23 tpy
108-88-3	Toluene	2.81E-04 lb/MMBtu	5.63E-02 tpy
1330-20-7	Xylenes (isomers and mixture)	1.93E-04 lb/MMBtu	3.86E-02 tpy
N/A	Polycylic Organic Matter	2.12E-04 lb/MMBtu	4.24E-02 tpy
	Polycyclic aromatic compounds(	2.12E-04 lb/MMBtu	
	Acenaphthene	4.68E-06 lb/MMBtu	
	Acenaphthylene	9.23E-06 lb/MMBtu	
	Anthracene	1.23E-06 lb/MMBtu	
	Benzo(a)anthracene	6.22E-07 lb/MMBtu	
	Benzo(b)fluoranthene	1.11E-06 lb/MMBtu	
	Benzo(k)fluoranthene	2.18E-07 lb/MMBtu	
	Benzo(a)pyrene	2.57E-07 lb/MMBtu	
	Benzo(g,h,l)perylene	5.56E-07 lb/MMBtu	
	Chrysene	1.53E-06 lb/MMBtu	
	Dibenz(a,h)anthracene	3.46E-07 lb/MMBtu	
	Fluoranthene	4.03E-06 lb/MMBtu	
	Fluorene	1.28E-05 lb/MMBtu	
	Ideno(1,2,3-cd)pyrene	4.14E-07 lb/MMBtu	
91-20-3	Naphthalene	1.30E-04 lb/MMBtu	
	Phenanathrene	4.08E-05 lb/MMBtu	
	Pyrene	3.71E-06 lb/MMBtu	

Total Potential HAP Emissions: 0.53 tpy

Notes:

1. Total heat consumption based on full-time or permit-limited operation of the following:

17.1 MW Generator Engines - Wartsila		1,115 gal/hr, each	
Potential Heat Consumption:	EU IDs 1-10	258,406	MMBtu/yr at maximum allowed operation of 1,680 hr/yr, combined
Vendor engine heat rate: 204 g/kW-hr			
17.1 MW Generator Engines - Wartsila		11 gal/hr, each	Dual-fired with 1% diesel[5]
Potential Heat Consumption:	EU IDs 1-10	132,098	MMBtu/yr
Vendor engine heat rate: 2 g/kW-hr			
1,490 hp Generator Engines - Cummins 1000DQFAD		72.2 gal/hr, each	
Potential Heat Consumption:	EU IDs 12 and 18	9,964	MMBtu/yr at maximum allowed operation of 1,000 hr/yr, combined
Total Potential Heat Input:		**400,467**	**MMBtu/yr**
EU IDs 1-10 diesel (100%) fuel consumption rate:		204	g/kW-hr
EU IDs 1-10 diesel (1%) fuel consumption rate:		2	g/kW-hr
Annual fuel use converted to MMBtu/yr based on a diesel fuel heat content:		138,000	Btu/gal

2. Reference: AP-42, Table 3.4-3.
3. Formaldehyde emission rate for EU IDs 12 and 18 only.
4. Formaldehyde emissions are based on source testing conducted using Method 323. The source test report was submitted to ADEC on April 2, 2015.
5. When operating on natural gas, EU IDs 1 through 10 burn one percent diesel.
6. See Table B-12 for fuel consumption rates from vendor data for EU IDs 1 through 10.
7. See Attachment C for fuel consumption rates from vendor data for EU IDs 12 and 18.

Table B-17. Matanuska Electric Association - Eklutna Generation Station
Estimated Potential HAP Emissions - Natural Gas Boilers

Maximum Total Heat Input without Catalytic Oxidation: 350 MMscf/yr

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations	
CAS No.	**Chemical Name**	**Emission Factor [2]**	**Estimated Emissions**
106467	1,4-Dichlorobenzene(p)	1.20E-03 lb/MMscf	2.100E-04 tpy
N/A	Arsenic Compounds	2.00E-04 lb/MMscf	3.499E-05 tpy
71432	Benzene	2.10E-03 lb/MMscf	3.674E-04 tpy
N/A	Beryllium Compounds	1.20E-05 lb/MMscf	2.100E-06 tpy
N/A	Cadmium Compounds	1.10E-03 lb/MMscf	1.925E-04 tpy
N/A	Chromium Compounds	1.40E-03 lb/MMscf	2.450E-04 tpy
N/A	Cobalt Compounds	8.40E-05 lb/MMscf	1.470E-05 tpy
5000	Formaldehyde	7.52E-02 lb/MMscf	1.316E-02 tpy
110543	Hexane	1.80E+00 lb/MMscf	3.149E-01 tpy
N/A	Manganese Compounds	3.80E-04 lb/MMscf	6.649E-05 tpy
N/A	Mercury Compounds	2.60E-04 lb/MMscf	4.549E-05 tpy
N/A	Nickel Compounds	2.10E-03 lb/MMscf	3.674E-04 tpy
N/A	Polycyclic Organic Matter (POM)	6.98E-04 lb/MMscf	1.222E-04 tpy
	2-Methylnaphthalene	2.4E-05 lb/MMscf	
	3-Methylchloranthrene	1.8E-06 lb/MMscf	
	7,12-Dimethylbenz(a)anthracene	1.6E-05 lb/MMscf	
	Acenaphthene	1.8E-06 lb/MMscf	
	Acenaphthylene	1.8E-06 lb/MMscf	
	Anthracene	2.4E-06 lb/MMscf	
	Benzo(a)anthracene	1.8E-06 lb/MMscf	
	Benzo(a)pyrene	1.2E-06 lb/MMscf	
	Benzo(a)fluoranthene	1.8E-06 lb/MMscf	
	Benzo(g,h,i)perylene	1.2E-06 lb/MMscf	
	Benzo(k)fluroanthene	1.8E-06 lb/MMscf	
	Chrysene	1.8E-06 lb/MMscf	
	Dibenzo(a,h)anthracene	1.2E-06 lb/MMscf	
	Fluoranthene	3.0E-06 lb/MMscf	
	Fluorene	2.8E-06 lb/MMscf	
	Indeno(1,2,3-cd)pyrene	1.8E-06 lb/MMscf	
91203	Naphthalene	6.10E-04 lb/MMscf	
	Phenanathrene	1.7E-05 lb/MMscf	
	Pyrene	5.0E-06 lb/MMscf	
N/A	Selenium Compounds	2.4E-05 lb/MMscf	4.199E-06 tpy
108883	Toluene	3.40E-03 lb/MMscf	5.949E-04 tpy
		Total Potential HAP Emissions:	**0.33 tpy**

Notes:
1. Total fuel use based on maximum full-time operation or permit-limited operation as noted below:

15.8 MMBtu/hr Auxiliary Boilers - Cleaver-Brooks FLX200-1650		15,752	scf/hr, each
Potential Fuel Use:	EU IDs 13 and 14	275,975,040	scf/yr operating 8,760 hr/yr, each
7.0 MMBtu/hr Natural Gas Fuel Heater - ETI		8,444	scf/hr
Potential Fuel Use:	EU ID 17	73,966,520	scf/yr operating 8,760 hr/yr
	Total Potential Fuel Use:	**349,941,560**	**scf/yr**

2. Reference: AP-42, Tables 1.4-3, 1.4-4.
3. See Attachment C for fuel consumption rates from vendor data.

Table B-18. Matanuska Electric Association - Eklutna Generation Station
Estimated Potential HAP Emissions - Diesel Boilers

Maximum Total Fuel Use:	**110**	**kgal/yr**
Maximum Total Heat Input:	**0.0152**	**10^{12} Btu/yr**

Section 112 Hazardous Air Pollutants		Source Category Emission Calculations			
CAS No.	**Chemical Name**	**Emission Factor** [1]		**Estimated Emissions**	
79-00-5	1,1,2-Trichloroethane	2.36E-04	lb/kgal	1.302E-05	tpy
N/A	Arsenic Compounds	4.0	lb/10^{12} Btu	3.045E-05	tpy
71-43-2	Benzene	2.14E-04	lb/kgal	1.180E-05	tpy
N/A	Beryllium Compounds	3	lb/10^{12} Btu	2.283E-05	tpy
N/A	Cadmium Compounds	3	lb/10^{12} Btu	2.283E-05	tpy
N/A	Chromium Compounds	3	lb/10^{12} Btu	2.283E-05	tpy
100-41-4	Ethyl benzene	6.36E-05	lb/kgal	3.508E-06	tpy
5-00-0	Formaldehyde	3.30E-02	lb/kgal	1.820E-03	tpy
N/A	Lead Compounds	9	lb/10^{12} Btu	6.850E-05	tpy
N/A	Manganese Compounds	6	lb/10^{12} Btu	4.567E-05	tpy
N/A	Mercury Compounds	3	lb/10^{12} Btu	2.283E-05	tpy
71-55-6	Methyl chloroform (1,1,1-Trichloroethane)	2.36E-04	lb/kgal	1.302E-05	tpy
N/A	Nickel Compounds	3	lb/10^{12} Btu	2.283E-05	tpy
N/A	Polycyclic Organic Matter (POM)	3.30E-03	lb/kgal	1.820E-04	tpy
	Polycyclic aromatic compounds(PAH)	1.19E-03	lb/kgal		
83-32-9	Acenaphthene	2.11E-05	lb/kgal		
203-96-8	Acenaphthylene	2.53E-07	lb/kgal		
120-12-7	Anthracene	1.22E-06	lb/kgal		
56-55-3	Benzo(a)anthracene	4.01E-06	lb/kgal		
205-99-5	Benzo(b)fluoranthene	1.48E-06	lb/kgal		
191-24-2	Benzo(g,h,i)perylene	2.26E-06	lb/kgal		
218-01-9	Chrysene	2.38E-06	lb/kgal		
53-70-3	Dibenz(a,h)anthracene	1.67E-06	lb/kgal		
206-44-0	Fluoranthene	4.84E-06	lb/kgal		
86-73-7	Fluorene	4.47E-06	lb/kgal		
193-39-5	Ideno(1,2,3-cd)pyrene	2.14E-06	lb/kgal		
91-20-3	Naphthalene	1.13E-03	lb/kgal		
85-01-8	Phenanathrene	1.05E-05	lb/kgal		
129-00-0	Pyrene	4.25E-06	lb/kgal		
N/A	Selenium Compounds	15	lb/10^{12} Btu	1.142E-04	tpy
108-88-3	Toluene	6.20E-03	lb/kgal	3.420E-04	tpy
1330-20-7	Xylenes (isomers and mixture)	1.09E-04	lb/kgal	6.012E-06	tpy
		Total Potential HAP Emissions:		**0.003**	**tpy**

Notes:
1. Reference: AP-42, Tables 1.3-8, 1.3-9, and 1.3-10.
2. Total heater fuel use based on full time operation of the following:

15.8 MMBtu/hr Auxiliary Boilers - Cleaver-Brooks FLX200-1650	110	gal/hr, each
Potential Fuel Use: EU IDs 13 and 14	110,310	gal/yr at maximum allowed operation of 1,000 hr/yr, combined
Total Potential Fuel Use:	**110,310**	**gal/yr**
Annual fuel use converted to MMBtu/yr based on a diesel fuel heat content:	138,000	Btu/gal

3. See Attachment C for fuel consumption rates from vendor data.

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	Eklutna Generation Station Diesel Storage Tank
City:	Anchorage
State:	Alaska
Company:	Matanuska Electric Association, Inc.
Type of Tank:	Vertical Fixed Roof Tank
Description:	10,401 bbl tank
Tank Dimensions	
Shell Height (ft):	32.00
Diameter (ft):	52.00
Liquid Height (ft) :	27.75
Avg. Liquid Height (ft):	20.00
Volume (gallons):	436,842.00
Turnovers:	2.00
Net Throughput(gal/yr):	873,684.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Anchorage, Alaska (Avg Atmospheric Pressure = 14.56 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Eklutna Generation Station Diesel Storage Tank - Vertical Fixed Roof Tank
Anchorage, Alaska

		Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp	Vapor Pressure (psia)			Vapor Mol.	Liquid Mass	Vapor Mass	Mol.	Basis for Vapor Pressure
Mixture/Component	Month	Avg.	Min.	Max.	(deg F)	Avg.	Min.	Max.	Weight.	Fract.	Fract.	Weight	Calculations
Distillate fuel oil no. 2	All	36.95	33.59	40.30	35.93	0.0031	0.0031	0.0031	130.0000			188.00	Option 1: VP40 = .0031

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Eklutna Generation Station Diesel Storage Tank - Vertical Fixed Roof Tank
Anchorage, Alaska

Annual Emission Calcaulations	
Standing Losses (lb):	16.7908
Vapor Space Volume (cu ft):	26,588.9322
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.0229
Vented Vapor Saturation Factor:	0.9979
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	26,588.9322
Tank Diameter (ft):	52.0000
Vapor Space Outage (ft):	12.5200
Tank Shell Height (ft):	32.0000
Average Liquid Height (ft):	20.0000
Roof Outage (ft):	0.5200
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.5200
Roof Height (ft):	0.0000
Roof Slope (ft/ft):	0.0600
Shell Radius (ft):	26.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0031
Daily Avg. Liquid Surface Temp. (deg. R):	496.6154
Daily Average Ambient Temp. (deg. F):	35.9125
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	495.6025
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	760.7341
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0229
Daily Vapor Temperature Range (deg. R):	13.4311
Daily Vapor Pressure Range (psia):	0.0000
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0031
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0031
Daily Avg. Liquid Surface Temp. (deg R):	496.6154
Daily Min. Liquid Surface Temp. (deg R):	493.2576
Daily Max. Liquid Surface Temp. (deg R):	499.9731
Daily Ambient Temp. Range (deg. R):	13.6250
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9979
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0031
Vapor Space Outage (ft):	12.5200

Working Losses (lb):	8.3832
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0031
Annual Net Throughput (gal/yr.):	873,684.0000
Annual Turnovers:	2.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	436,842.0000
Maximum Liquid Height (ft):	27.7500
Tank Diameter (ft):	52.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	25.1740

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Eklutna Generation Station Diesel Storage Tank - Vertical Fixed Roof Tank
Anchorage, Alaska

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	8.38	16.79	25.17

Attachment C

Supporting Information for Requested Changes to Condition 8

Attachment C

C.1 Request to Revise the Low Range of the Ammonia Injection Rate in Permit Condition 8.1(a) of Minor Air Permit Number AQ1086MSS02

In compliance with Condition 8, the ten Wartsila generator engines, emission unit identification numbers (EU IDs) 1 through 10, have had Selective Catalytic Reduction (SCR) and Catalytic Oxidizer (CATOX) emission control equipment installed. The engines and emission control equipment are maintained per manufacturer's instructions. The equipment controls nitrogen oxides (NO_X) emissions by injecting ammonia into the SCR catalyst units. The ammonia dosing system uses the raw exhaust gas nitric oxide (NO) concentration value from the engine exhaust before entering the SCR units as a coarse adjustment of the ammonia injection rate into the SCR units. The dosing system then detects and uses the NO concentration in the exhaust gas after leaving the SCR units as a fine adjustment of the ammonia injection rate. The NO emission value is compared to the NO control value and the ammonia injection is adjusted accordingly. The NO monitoring system consists of two NO sample analyzers measuring the NO concentration of the exhaust gas. The two NO analyzers alternate between collecting data and calibration. One of the two controllers is always in operation.

Per Condition 7, the performance test was conducted from February 3 through 5, 2015, on EU ID 10. The source test report was submitted to the Alaska Department of Environmental Conservation (ADEC) on April 2, 2015. During the performance test, measurements of the NO and NO_X emission rates were collected. This measured data provided the basis for evaluating NO_X emissions from EU IDs 1 through 10.

Monthly operational data for the parameters included in Condition 8.1 are collected for EU IDs 1 through 10 from a data logging system. Originally, vendor data were provided in Permit AQ1086MSS02 to determine the estimated operational ranges for the emission control system before EU IDs 1 through 10 began startup. Two full months of logged data are now available for all ten engines, specifically the months of April and May, 2015. The SCR control system install on each of these engines is operating better than expected and require an ammonia injection rate less than six gallons per hour (gal/hr) to adequately control NO_X emissions while operating on natural gas. The following operational data table supports the request to revise the minimum ammonia injection rate in Condition 8.1(a). The three-hour rolling averages of NO_X emissions in pounds per hour (lb/hr) are also provided in Table 1, demonstrating that emission rates are within emission rates listed in Condition 7.4.

Table 1 - Ammonia Injection Rate (3-hour rolling average)

EU ID	April 2015		May 2015	
	Ammonia Injection Rate (3-hour rolling, low range) (gal/hr)	Average NO_X Emissions[1] (lb/hr)	Ammonia Injection Rate (3-hour rolling, low range) (gal/hr)	Average NO_X Emissions[1] (lb/hr)
1	2.1	1.06	2.0	1.07
2	2.2	0.55	3.1	0.47
3	2.2	0.56	2.2	0.51
4	3.8	1.33	3.2	1.36
5	2.8	1.05	3.3	0.99
6	2.6	1.07	3.2	0.98
7	3.2	1.13	3.6	0.95
8	1.2	1.16	2.1	0.90
9	1.3	0.64	2.6	0.57
10	3.9	0.78	3.4	0.49

1) The NO_X values are based on actual NO measurements collected from the data logging system. The relationship between the NO_X emission rates versus the NO emission rates were determined based on the performance test conducted from February 3 through 5, 2015, during which concentrations of both the NO_X and NO emissions were collected concurrently.

Based on this data set, the request is being made to revise the ammonia reagent injection rate range for the SCR emission control system to a minimum of 1.0 gal/hr, while operating on natural gas.

C.2 Request to Revise the Pressure Drop Range across the Control Equipment in Permit Condition 8.1(c) of Minor Air Permit Number AQ1086MSS02

Monthly operational data for the pressure drop parameters included in Condition 8.1(c) are collected from a data logging system. Vendor data were provided for Permit AQ1086MSS02 to determine the estimated operational range for Condition 8.1(c) before EU IDs 1 through 10 began operation. Two full months of data are now available for all ten engines, specifically April and May, 2015.

The actual pressure drop across the combined control system installed on each Wartsila generator engines, EU IDs 1 through 10, is slightly above the minimum drop permitted in Condition 8.1(c). The request to revise Condition 8.1(c) is to allow for data to be averaged over a three-hour rolling period, while operating on natural gas. The request also includes changing the water depth range because this adjustment will provide compliance flexibility to reflect the actual operational pressure drop range. The following table provides monthly data to support the request to revise the pressure drop range in Condition 8.1(c) to an operational range of 1.5 to 9.5 inches of water. As the control system ages, the pressure drop is expected to increase. The pressure drop is not expected to exceed the 9.5 inches of water.

Table 2 - Pressure Drop Range (3-hour rolling average)

EU ID	April 2015	May 2015
	Pressure Drop Range (inches of water)	Pressure Drop Range (inches of water)
1	2.7 to 3.6	2.7 to 3.6
2	2.1 to 3.5	2.4 to 3.4
3	2.4 to 3.4	2.6 to 3.3
4	2.4 to 3.6	2.5 to 3.2
5	2.6 to 4.6	2.7 to 5.5
6	2.4 to 4.7	1.8 to 4.4
7	2.1 to 3.0	2.0 to 2.8
8	2.4 to 3.6	2.4 to 3.2
9	2.2 to 3.6	2.4 to 3.2
10	2.4 to 3.4	2.4 to 3.2

Attachment D

Air Quality Control Minor Permit AQ1086MSS02

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL MINOR PERMIT

Permit AQ1086MSS02 **Final – December 31, 2013**
Rescinds Minor Permit AQ1086MSS01

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ1086MSS02 to the Permittee listed below.

Permittee:	Matanuska Electric Association P. O. Box 2929 163 East Industrial Way Palmer, Alaska 99645
Owner:	Matanuska Electric Association
Stationary Source	Eklutna Generation Station
Location:	Latitude 61° 27' 35" North; Longitude 149° 20' 34" West
Physical Address:	16 miles SW of Palmer, East of Glenn Hwy, near Eklutna
Permit Contact:	Gary Peers, (907) 761-9367; Gary.Peers@mea.com
Project:	Revision of Emission Unit Inventory and Operating Hours

This permit authorizes modifications to an existing Title I permit under 18 AAC 50.508(6). The permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit

James Baumgartner FOR

John F. Kuterbach
Manager, Air Permits Program

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Section 1. Emission Inventory

1. Emission Units (EU) Authorization. The Permittee is authorized to install and operate emission units (EUs) listed in Table 1. Except as noted elsewhere in the permit, the information in Table 1 is for information purposes only. The specific unit descriptions do not restrict the Permittee from replacing an emission unit identified in Table 1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement emission unit, including any applicable minor or construction permit requirements.

Table 1 –Emission Unit Inventory

EU	Description	Make / Model	Rating	Fuel Type	Install Date
1	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
2	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
3	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
4	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
5	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
6	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
7	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
8	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
9	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
10	Generator Engine	Wartsila 18V50DF	17.1 MW	NG / ULSD	TBD
11	Firewater Pump	John Deere JU6H-UFADN0	197 hp	ULSD	TBD
12	Black Start Generator	Cummins 1000DQFAD	1,490 hp	ULSD	TBD
13	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMbtu/hr	NG / ULSD	TBD
14	Auxiliary Boiler	Cleaver-Brooks FLX200-1650	15.75 MMbtu/hr	NG / ULSD	TBD
15	Diesel Storage Tank	To Be Determined (TBD)	509,000 gal	Diesel	TBD
16	Diesel Storage Tank	To Be Determined (TBD)	509,000 gal	Diesel	TBD
17	Natural Gas Fuel Heater	ETI	7.0 MMBtu/hr	Natural Gas	TBD
18	Black Start Generator	Cummins 1000DQFAD	1,490 hp	ULSD	TBD

Table Notes:
NG / ULSD: Natural Gas / Ultra Low Sulfur Diesel
TBD: To Be Determined

1.1 The Permittee shall maintain the equipment listed in Table 1 according to manufacturer’s or operator’s maintenance procedures and shall keep copies of the maintenance procedures.

Section 2. Emission Fees

2. **Assessable Emissions.** The Permittee shall pay the Department an annual emission fee based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410(b). The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities greater than 10 tons per year (tpy). The quantity for which fees will be assessed is the lesser of:

2.1 the stationary source's assessable potential to emit of 795 tpy; or

2.2 the stationary source's projected annual rate of emissions that will occur from July 1st to the following June 30th, based upon actual annual emissions emitted during the most recent calendar year or another 12-month period approved in writing by the Department, when demonstrated by

a. an enforceable test method described in 18 AAC 50.220;

b. material balance calculations;

c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035; or

d. other methods and calculations approved by the Department**.**

3. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

3.1 no later than March 31st of each year, the Permittee may submit an estimate of the stationary source's assessable emissions to the Department, Air Permits Program, ATTN: Assessable Emissions Estimate, 410 Willoughby Ave., Juneau, AK 99801-1795**;** the submittal must include all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates; or

3.2 if no estimate is submitted on or before March 31st of each year, emission fees for the next fiscal year will be based on the potential to emit set forth in Condition 2.1.

Section 3. Requirements to Avoid Classification under PSD

4. **Operation Hour Limits for EUs 1 through 10 When Burning Ultra Low Sulfur Diesel (ULSD):** The Permittee shall limit the combined hours of operation of EUs 1-10 to no more than 1,680 hours per 12-month rolling period when firing ULSD exclusively.

   4.1 The Permittee shall burn only natural gas and ultra low sulfur diesel (ULSD) in EUs 1-10.

   4.2 Install and maintain a non-resettable hour meter on each of EUs 1-10.

   4.3 Monitor and record the hours of operation each month for each of EUs 1-10 when firing ULSD exclusively.

   4.4 By the end of each calendar month, calculate and record the combined hours of operation for EUs 1-10 when firing ULSD exclusively during the previous month, then calculate the 12-month rolling total combined hours for EUs 1-10 when firing ULSD exclusively.

   4.5 Report in the operating report under Condition 21 the rolling 12-month combined hours of operation when EUs 1-10 firing ULSD exclusively.

   4.6 Notify the Department under Condition 20 if the consecutive 12-month total combined hours of operation, for EUs 1-10, when firing ULSD exclusively exceed 1,680 hours.

5. **Operation Hour Limits for EU 11:** The Permittee shall limit the operation of EU 11 to no more than 500 hours per year.

   5.1 Install and maintain a non-resettable hour meter on EU 11.

   5.2 Monitor and record the monthly hours of operation for EU 11.

   5.3 By the end of each month, calculate and record the operating hours of EU 11 for the previous month.

   5.4 Report in the operating report under Condition 21 the rolling 12-month hours of operation of EU 11.

   5.5 Notify the Department under Condition 20 if the rolling 12-month hours of operation for EU 11 exceed 500 hours.

6. **Operation Hour Limits for EUs 13 and 14 When Burning ULSD:** The Permittee shall limit the combined operation hours of EUs 13 and 14 to no more than 1,000 hours per rolling 12-month period when exclusively firing ULSD.

   6.1 The Permittee shall fire only natural gas and ULSD in EUs 13 and 14.

   6.2 Install and maintain a non-resettable hour meter on each of EUs 13 and 14.

   6.3 Monitor and record the monthly operating hours for each of EUs 13 and 14 when firing exclusively ULSD.

6.4 By the end of each month, calculate and record the total combined operating hours of EUs 13 and 14 when firing ULSD exclusively during the previous month, then calculate the 12-month rolling total combined hours for EUs 13 and 14 when firing ULSD exclusively.

6.5 Report in the operating report under Condition 21 the rolling 12-month combined operating hours of EUs 13 and 14 when firing ULSD exclusively.

6.6 Notify the Department under Condition 20 if the rolling 12-month total combined hours of operation, for EUs 13 and 14, when firing ULSD exclusively, exceeds 1,000 hours.

7. **Performance Test**: Within 180 days of start-up of any of EUs 1-10, the Permittee shall conduct performance testing on any one of EUs 1-10 when operating on natural gas. The Permittee shall conduct the test downstream of the combined SCR and CATOX control equipment installed on the equipment and according to Section 9 of this permit.

7.1 The Permittee shall perform the source test at three load points that span the operating range of the engine and includes the highest achievable operating load and lowest typical operating load.

7.2 The Permittee shall calculate the emission rates for nitrogen oxides (NOx), carbon monoxide (CO), particulate matter with aerodynamic diameter not exceeding 10 microns (PM-10), and volatile organic compounds (VOC) in pounds per hour (lb/hr).

7.3 The Permittee shall report the results of the performance test, including the emissions rates calculated in Condition 7.2, to the Department within 60 calendar days after completing the test.

7.4 If the emission rates, when operating on natural gas, exceed 3.43 lb/hr for NOx, 4.52 lb/hr for CO, 4.89 lb/hr for PM-10, or 3.43 lb/hr for VOC respectively:

(a) For each month, calculate the rolling 12-month NOx, CO, PM-10, and VOC emissions from EUs 1-10, 11, 12, 13, 14, 17 and 18, using the emission rates determined in Condition 7 and operating hours for the emission units; and

(b) Submit the rolling 12-month NOx, CO, PM-10, and VOC emissions from EUs 1-10, 11, 12, 13, 14, 17, and 18 in the operating report under Condition 21.

(c) If the rolling 12-month emissions for NOx, CO, PM-10, or VOC exceed 250 tpy, submit a Prevention of Significant Deterioration application within 120 days of discovering the exceedance.

8. **Control Equipment:** The Permittee shall install, operate, and maintain a combined Selective Catalytic Reduction (SCR) and Catalytic Oxidizer (CATOX) control equipment downstream of each of EUs 1-10 according to the manufacturer's instructions and as follows:

8.1 For the combined control equipment[1], monitor and record hourly

[1] SCR and CATOX with the CATOX downstream of the SCR.

(a) the rate of injection of the reducing aqueous ammonia reagent into the flue gas leaving the emission unit. The rate of injection of ammonia averaged over rolling three hours shall be no less than 6 gallons per hour (gal/hr) and no more than 38.5 gal/hr[2], except during startup and shutdown, and should be high enough to achieve the emission rate listed in Condition 7.4.

(b) the temperature of the flue gas leaving the combined control equipment. The temperature of the flue gas leaving the combined control equipment shall be no less than 536°F and no more than 997°F[3], except during startup and shutdown.

(c) pressure drop across the combined control equipment. The pressure drop shall be no less than two inches of water and no more than 10 inches of water, except during startup and shutdown.

8.2 Keep on site the necessary manufacturer-recommended spare parts, reagents, catalysts, and operation manual for the control equipment.

8.3 In case of equipment malfunction, implement manufacturer-recommended corrective actions and record:

(a) complete description of the corrective action; and

(b) date(s) of the corrective action

8.4 Keep records of:

(a) all control equipment system repairs;

(b) hourly operating parameters established in Condition 8.1, dates and times each control equipment is started up or shut down.

(c) System alarm logs including time and date of occurrence

(d) receipts for all aqueous ammonia purchases (with dates and quantities);

8.5 Report under Condition 20 all

(a) Control equipment malfunctions and associated corrective actions;

(b) Operating parameters that are outside the ranges in Condition 8.1.

(c) Periods (starting and ending hour) during which a control equipment was not operating within the ranges established in Condition 8.1 while its associated generator was operating.

[2] The injection rates are from the manufacturer's specifications.
[3] The temperature rates are from the manufacturer specifications.

Section 4. Requirements to Avoid Classification as a HAP Major Source

9. Formaldehyde (CH_2O) Emission Limit: The Permittee shall limit CH_2O emissions from EUs 1-10 while firing natural gas to no more than 9.6 tpy during any consecutive 12 months. The Permittee shall monitor, record, and report CH_2O emissions as follows:

9.1 Within 180 days of startup of any of EUs 1-10, the Permittee shall conduct a performance test on any of EUs 1-10 when operating on natural gas downstream of the combined control equipment (SCR and CATOX) installed on the unit. Calculate CH_2O emission rates in pounds per hour (lb/hr). The Permittee may conduct performance tests on more than one unit and average the emission rates from the multiple tests. The Permittee shall conduct the performance tests according to Section 9 of this permit.

(a) The Permittee shall perform the source test at three load points that span the operating range of the engine and includes the highest achievable operating load and the lowest typical operating load.

(b) The Permittee shall report the results of the performance test(s) to the Department within 60 calendar days after completing the test(s).

9.2 Monitor and record the hours of operation each month for each of EUs 1-10 when firing natural gas.

9.3 By the end of each calendar month, calculate and record the combined hours of operation for EUs 1-10 when firing natural gas for the previous month.

9.4 By the end of each month,

(a) calculate and record the CH_2O emissions from all of EUs 1-10 operated during the previous month using the equation:

$A = (B \times C) \div 2000$ pounds per ton

Where:
A = tons of CH_2O emitted by all of EUs 1-10 operated during the previous month;
B= 0.23 lb CH_2O/hr[4] or the lb CH_2O determined in Condition 9.1; and
C = number of hours all of EUs 1-10 operated on natural gas during the previous month, calculated and recorded in Condition 9.3.

(b) calculate and record the CH_2O emissions from all of EUs 1-10 operated during the rolling 12-month by summing up the monthly emissions in Condition 9.4(a) for the rolling 12-months.

9.5 Report the consecutive 12-month CH_2O emissions calculated and recorded in Condition 9.4(b).

(a) in the operating report under Condition 21; and

(b) under Condition 20 if the consecutive 12-month emissions exceed 9.6 tpy.

[4] The emission factor EUs 1-10 as given by the manufacturer.

Section 5. State Emission Standards

10. **Visible Emissions**. The Permittee shall not cause or allow visible emissions (VE), excluding condensed water vapor, emitted by EUs 1-14, 17, and 18 to reduce visibility through the exhaust effluent by more than 20 percent averaged over any six consecutive minutes.

10.1 **Visible Emission Monitoring**: Within 30 days of starting up of any EU listed in Table 1 operating exclusively on diesel, the Permittee shall perform an initial VE test of the EU using the Method 9 Plan.

10.2 **Visible Emissions Reporting**: The Permittee shall report the Method 9 VE test performed on any EU operating exclusively on diesel to the Department in the next operating report required under Condition 21.

(i) If the Permittee observes VE from the exhaust of any EU (while operating exclusively on diesel) during the test exceeds the standard in Condition 10, the Permittee shall take corrective action, repeat the VE test on the next start-up of the EU (while operating exclusively on diesel), and report the results of the VE test to the Department in the next operating report required under Condition 21.

11. **Particulate Matter**: The Permittee shall not cause or allow particulate matter (PM) emitted from EUs 1-14, 17, and 18 to exceed 0.05 grains per dry standard cubic foot of exhaust gas corrected to standard conditions and averaged over three hours.

11.1 **Particulate Matter Monitoring, Recording, and Reporting for Diesel Engines**: The Permittee shall monitor PM emissions, record, and report as described in Conditions 10.1 and 10.2.

12. **Sulfur Compound Emissions**: The Permittee shall not cause or allow sulfur compounds emissions, expressed as SO_2 from EUs 1 through 14, 17, and 18 to exceed 500 ppmv averaged over three hours.

12.1 The Permittee shall monitor, record, and report as described in Condition 15.

Section 6. Protection of Ambient Air Quality

13. Annual NO_2 Ambient Air Quality Protection: To protect the annual NO_2 ambient air quality standard, the Permittee shall:

13.1 For EUs 1-10, the Permittee shall maintain a release height for each stack that equals or exceeds 30.0 meters above grade.

13.2 Provide as-built drawings of the exhaust stacks or measurements of the release point above grade of the exhaust stacks in the next operating report required under Condition 21 for the period in which any of EUs 1-10 begins operation.

14. Annual NO_2 and 24-hr PM-10 Ambient Air Quality Protection: To protect the annual NO_2 and 24-hr PM-10, the combined operating hours for EUs 12 and 18 shall not exceed 1,000 hours per rolling 12-month period.

14.1 Install and maintain a non-resettable hour meter on each of EUs 12 and 18.

14.2 Monitor and record the hours of operation of each emission unit and the combined hours of operation for EUs 12 and 18 for each month.

14.3 At the end of each month, calculate and record for the previous month, the combined hours of operation for EU 12 and EU 18 during the month, then calculate the combined 12-month rolling total hours of operation by adding the hours of operation for the previous 11 months.

14.4 Report in the operating report under Condition 21 the combined rolling 12-month hours of operation for EUs 12 and 18.

14.5 Notify the Department under Condition 20 should the combined consecutive 12-month operating hours for EU 12 and 18 exceed 1,000 hours.

Section 7. Requirements to Avoid Minor Permitting under 18 AAC 50.502(c)(1)(c)

15. **Fuel Sulfur Requirements:** The Permittee shall monitor the sulfur content of the ULSD and hydrogen sulfide (H_2S) content of the natural gas burned as follows:

15.1 The H_2S content of the natural gas burned in EUs 1-10, 13, 14, and 17 shall not exceed 20 parts per million by volume (ppmv).

(a) Monitor and record the H_2S content of the natural gas monthly by obtaining and keeping a certified letter from the supplier stipulating that the natural gas supplied during the month does not contain more than 20 ppmv H_2S.

(b) Report in the operating report under Condition 21 the monthly H_2S content of the natural gas. Report under Condition 20 if the H_2S content of the natural gas exceeds 20 ppmv.

15.2 The sulfur content of the diesel fuel burned in EUs 1-10, 13, and 14 when burning diesel and in EUs 11, 12, and 18 shall not exceed 15 parts per million by weight (ppmw) of sulfur.

(a) Monitor and record monthly the sulfur content of the diesel fuel burned by obtaining and keeping a certified letter from the diesel fuel supplier that the diesel fuel supplied during the month was ULSD.

(b) Report in the operating report under Condition 21 the type of diesel fuel received for each shipment. Report under Condition 20 if the fuel received was not ULSD.

Section 8. General Recordkeeping, Reporting, and Certification Requirements

16. **Certification.** The Permittee shall certify all reports, or other documents submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete." Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

17. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall send two copies of reports, compliance certifications, and other submittals required by this permit to ADEC, Air Permits Program, 610 University Ave., Fairbanks, AK 99709-3643, ATTN: Compliance Technician. The Permittee may upon consultation with the Compliance Technician regarding software compatibility, provide electronic copies of data reports, emission source test reports, or other records under a cover letter certified in accordance with Condition 16.

18. **Information Requests.** The Permittee shall furnish to the Department, within a reasonable time, any information the Department requests in writing to determine whether cause exists to modify, revoke, reissue, or terminate the permit or to determine compliance with the permit. Upon request, the Permittee shall furnish to the Department copies of records required to be kept by the permit. The Department may require the Permittee to furnish copies of those records directly to the federal administrator.

19. **Recordkeeping Requirements.** The Permittee shall keep all records required by this permit for at least five years after the date of collection, including:

19.1 copies of all reports and certifications submitted pursuant to this section of the permit; and

19.2 records of all monitoring required by this permit, and information about the monitoring including (if applicable):

a. calibration and maintenance records, original strip chart or computer-based recordings for continuous monitoring instrumentation;

b. sampling dates and times of sampling or measurements;

c. the operating conditions that existed at the time of sampling or measurement;

d. the date analyses were performed;

e. the location where samples were taken;

f. the company or entity that performed the sampling and analyses;

g. the analytical techniques or methods used in the analyses; and

h. the results of the analyses.

20. Excess Emissions and Permit Deviation Reports.

20.1 Except as provided in Condition 22, the Permittee shall report all emissions or operations that exceed or deviate from the requirements of this permit as follows:

a. In accordance with 18 AAC 50.240(c), as soon as possible after the event commenced or is discovered, report

(i) emissions that present a potential threat to human health or safety; and

(ii) excess emissions that the Permittee believes to be unavoidable;

b. in accordance with 18 AAC 50.235(a), within two working days after the event commenced or was discovered, report an unavoidable emergency, malfunction, or nonroutine repair that caused emissions in excess of a technology based emissions standard;

c. report all other excess emissions and permit deviations

(i) within 30 days of the end of the month in which emissions or deviation occurs or is discovered, except as provided in Conditions 20.1c(ii) and 20.1c(iii);

(ii) if a continuous or recurring excess emissions is not corrected within 48 hours of discovery, within 72 hours of discovery unless the Department provides written permission to report under Condition 20.1c(i); and

(iii) for failure to monitor, as required in other applicable conditions of this permit.

20.2 The Permittee must report using either the Department's on-line form, or if the Permittee prefers, the form contained in Attachment 2. The Permittee must provide all information called for by the form that is used.

20.3 If requested by the Department, the Permittee shall provide a more detailed written report as requested to follow up an excess emissions report.

21. Operating Reports. During the life of this permit, the Permittee shall submit to the Department an original and two copies of an operating report by August 1st for the period January 1st through June 30th of the current year and by February 1st for the period July 1st through December 31st of the previous year.

21.1 The operating report must include all information required to be in operating reports by other conditions of this permit

21.2 If excess emissions or permit deviations that occurred during the reporting period are not reported under Condition 21.1, either

a. The Permittee shall identify

(i) the date of the deviation;

(ii) the equipment involved;

(iii) the permit condition affected;

(iv) any corrective action or preventative measures taken and the date of such actions; or;

b. when excess emissions or permit deviations have already been reported under Condition 20 the Permittee may cite the date or dates of those reports.

22. Air Pollution Prohibited. No person may permit any emissions 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.

22.1 If emissions present a potential threat to health or safety, the Permittee shall report any such emissions according to Condition 20.

22.2 As soon as practicable after becoming aware of a complaint that is attributable to emissions from the stationary source, the Permittee shall investigate the complaint to identify emissions that the Permittee believes have caused or are causing a violation of Condition 22.

22.3 The Permittee shall initiate and complete corrective action necessary to eliminate any violation identified by a complaint or investigation as soon as practicable if

a. after investigation because of complaint or other reason, the Permittee believes that emissions from the stationary source have caused or are causing a violation of Condition 22; or

b. the Department notifies the Permittee that it has found a violation of Condition 22.

22.4 The Permittee shall keep records of

a. the date and time, and nature of all emissions complaints received;

b. the name of the person or persons that complained, if known;

c. a summary of any investigation, including reasons the Permittee does or does not believe the emissions have caused a violation of Condition 22; and

d. any corrective actions taken or planned for complaints attributable to emissions from the stationary source

22.5 With each operating report under Condition 21, the Permittee shall include a brief summary report which must include

a. the number of complaints received;

b. the number of times the Permittee or the Department found corrective action necessary;

c. the number of times action was taken on a complaint within 24 hours; and

d. the status of corrective actions the Permittee or Department found necessary that were not taken within 24 hours.

22.6 The Permittee shall notify the Department of a complaint that is attributable to emissions from the stationary source within 24 hours after receiving the complaint, unless the Permittee has initiated corrective action within 24 hours of receiving the complaint.

Section 9. General Source Test Requirements

23. **Requested Source Tests.** In addition to any source testing explicitly required by this permit, the Permittee shall conduct source testing as requested by the Department to determine compliance with applicable permit requirements.

24. **Operating Conditions.** Unless otherwise specified by an applicable requirement or test method, the Permittee shall conduct source testing

24.1 at a point or points that characterize the actual discharge into the ambient air; and

24.2 at the maximum rated burning or operating capacity of the source or another rate determined by the Department to characterize the actual discharge into the ambient air

25. **Reference Test Methods.** The Permittee shall use the following references for test methods when conducting source testing for compliance with this permit:

25.1 Source testing for the reduction in visibility through the exhaust effluent must be conducted in accordance with the procedures set out in 40 C.F.R. 60, Appendix A, Reference Method 9. The Permittee may use the form in Attachment 1 of this permit to record data.

25.2 Source testing for emissions of total particulate matter, sulfur compounds, nitrogen compounds, carbon monoxide, lead, volatile organic compounds, fluorides, sulfuric acid mist, municipal waste combustor organics, metals and acid gases must be conducted in accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A.

25.3 Source testing for emissions of PM-10 must be conducted in accordance with the procedures specified in 40 C.F.R. 51, Appendix M, Methods 201 or 201A and 202.

25.4 Source testing for emissions of any contaminant may be determined using an alternative method approved by the Department in accordance with 40 C.F.R. 63 Appendix A, Method 301.

26. **Test Deadline Extension.** The Permittee may request an extension to a source test deadline established by the Department. The Permittee may delay a source test beyond the original deadline only if the extension is approved in writing by the Department’s appropriate division director or designee.

27. **Test Plans.** Before conducting any source tests, the Permittee shall submit a plan to the Department. The plan must include the methods and procedures to be used for sampling, testing, and quality assurance, and must specify how the emissions unit will operate during the test and how the Permittee will document that operation. The Permittee shall submit a complete test plan at least 30 days before the scheduled date of any test unless the Department agrees in writing to some other time period. Retesting may be done without resubmitting the plan.

28. **Test Notification.** At least 10 days before conducting a source test, the Permittee shall give the Department written notice of the date and time the source test will begin.

29. **Test Reports.** Within 60 days after completing a source test, the Permittee shall submit two copies of the results in the format set out in the *Source Test Report Outline*, adopted by reference in 18 AAC 50.030. The Permittee shall certify the results as set out in Condition 16. If requested in writing by the Department, the Permittee must provide preliminary results in a shorter period of time specified by the Department.

Section 10. Standard Terms and Conditions

30. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

30.1 an enforcement action; or

30.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

31. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

32. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

33. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

34. The permit does not convey any property rights of any sort, nor any exclusive privilege.

Section 11. Permit Documentation

June 27, 2013	Matanuska Electric Association (MEA) submits a minor permit application to revise Minor Permit AQ1086MSS01
August 16, 2013	Department requests MEA to submit an air quality analysis to support their request to revise a permit condition that protects ambient air quality and provide the basis for 500 operating hours per year owner requested limit for EU ID 11.
August 29, 2013	MEA responds to the Department request and explains the requested revisions do not require an ambient air quality analysis and assumed an EPA recommended default 500 operating hours per year for EU ID
September 3, 2013	Department agrees that the requested revisions do not require an ambient air quality analysis but informed MEA that the Department will treat the 500 operating hours as an owner requested limit because EU 11 does not fall into the equipment types covered by the EPA default recommended operating hours.
September 18, 2013	MEA alerts the Department to re-write the condition corresponding to Condition 9.2 of Minor Permit AQ1086MSS01 to reflect the Department’s intent.
October 2, 2013	Department requests MEA to submit the specifications for the proposed Selective Catalytic Reduction and Catalytic Oxidizer.
November 15, 2013	MEA submits an application supplement that contains specifications of the control equipment to the Department. The control equipment is a combined selective catalytic reduction and catalytic oxidizer.
December 18, 2013	MEA submits comments on the preliminary permit.

Section 12. Attachment 1: Visible Emissions Form

VISIBLE EMISSION OBSERVATION FORM

This form is designed to be used in conjunction with EPA Method 9, "Visual Determination of the Opacity of Emissions form Stationary Sources." Temporal changes in emission color, plume water droplet content, background color, sky conditions, observer position, etc. should be noted in the comments section adjacent to each minute of readings. Any information not dealt with elsewhere on the form should be noted under additional information. Following are brief descriptions of the type of information that needs to be entered on the form: for a more detailed discussion of each part of the form, refer to "Instructions for Use of Visible Emission Observation Form."

- Source Name: full company name, parent company or division or subsidiary information, if necessary.
- Address: street (not mailing or home office) address of facility where VE observation is being made.
- Phone (Key Contact): number for appropriate contact.
- Source ID Number: number from NEDS, agency file, etc.
- Process Equipment, Operating Mode: brief description of process equipment (include type of facility) and operating rate, % capacity, and/or mode (e.g. charging, tapping, shutdown).
- Control Equipment, Operating Mode: specify type of control device(s) and % utilization, control efficiency.
- Describe Emission Point: for identification purposes, stack or emission point appearance, location, and geometry; and whether emissions are confined (have a specifically designed outlet) or unconfined (fugitive).
- Height Above Ground Level: stack or emission point height relative to ground level; can use engineering drawings, Abney level, or clineometer.
- Height Relative to Observer: indicate height of emission point relative to the observation point.
- Distance from Observer: distance to emission point; can use rangefinder or map.
- Direction from Observer: direction plume is traveling from observer.
- Describe Emissions and Color: include physical characteristics, plume behavior (e.g., looping, lacy, condensing, fumigating, secondary particle formation, distance plume visible, etc.), and color of emissions (gray, brown, white, red, black, etc.). Note color changes in comments section.
- Visible Water Vapor Present?: check "yes" if visible water vapor is present.
- If Present, is Plume…: check "attached" if water droplet plume forms prior to exiting stack, and "detached" if water droplet plume forms after exiting stack.
- Point in Plume at Which Opacity was Determined: describe physical location in plume where readings were made (e.g., 1 ft above stack exit or 10 ft. after dissipation of water plume).
- Describe Plume Background: object plume is read against, include texture and atmospheric conditions (e.g., hazy).
- Background Color: sky blue, gray-white, new leaf green, etc.
- Sky Conditions: indicate cloud cover by percentage or by description (clear, scattered, broken, overcast).
- Wind Speed: record wind speed; can use Beaufort wind scale or hand-held anemometer to estimate.
- Wind Direction From: direction from which wind is blowing; can use compass to estimate to eight points.
- Ambient Temperature: in degrees Fahrenheit or Celsius.

  Wet Bulb Temperature: can be measured using a sling psychrometer

  RH Percent: relative humidity measured using a sling psychrometer; use local US Weather Bureau measurements only if nearby.
- Source Layout Sketch: include wind direction, sun position, associated stacks, roads, and other landmarks to fully identify location of emission point and observer position.

  Draw North Arrow: to determine, point line of sight in direction of emission point, place compass beside circle, and draw in arrow parallel to compass needle.

  Sun's Location: point line of sight in direction of emission point, move pen upright along sun location line, mark location of sun when pen's shadow crosses the observer's position.
- Observation Date: date observations conducted.
- Start Time, End Time: beginning and end times of observation period (e.g., 1635 or 4:35 p.m.).
- Data Set: percent opacity to nearest 5%; enter from left to right starting in left column. Use a second (third, etc.) form, if readings continue beyond 30 minutes. Use dash (-) for readings not made; explain in adjacent comments section.

  Comments: note changing observation conditions, plume characteristics, and/or reasons for missed readings.

  Range of Opacity: note highest and lowest opacity number.
- Observer's Name: print in full.

  Observer's Signature, Date: sign and date after performing VE observation.
- Organization: observer's employer.

Certified By, Date: name of "smoke school" certifying observer and date of most recent certification.

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY DIVISION - VISIBLE EMISSIONS OBSERVATION FORM

Page No.__________

Source Name		Type of Source	
Address			
City	State	Zip	
Phone # (Key Contact)		Source ID Number	
Process Equipment		Operating Mode	
Control Equipment		Operating Mode	
Describe Emission Point			
Height above ground level	Height relative to observer	Inclinometer Reading	
Distance From Observer		Direction From Observer Start End	
Describe Emissions & Color Start		End	
Visible Water Vapor Present? No Yes	If yes, determine approximate distance from the stack exit to where the plume was read		
Point in Plume at Which Opacity Was Determined			
Describe Plume Background Start End		Background Color Start End	
Sky Conditions: Start End			
Wind Speed		Wind Direction From Start End	
Ambient Temperature		Wet Bulb Temp	RH percent

NOTES: 1 Stack or Point Being Read 2 Wind Direction From
3 Observer Location 4 Sun Location 5 North Arrow 6 Other Stacks

Observation Date	Start Time	End Time	

Sec / Min	0	15	30	45	Comments
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Range of Opacity
Minimum Maximum

I have received a copy of these opacity observations		Print Observer's Name	
Print Name:		Observer's Signature	Date
Signature:			
Title	Date	Organization	
		Certified By:	Date

Section 13. Attachment 2: ADEC Notification Form[5]

Excess Emissions and Permit Deviation Reporting
State of Alaska Department of Environmental Conservation
Division of Air Quality

Eklutna Generation Station	AQ1086MSS02
Stationary Source Name	**Air Quality Permit No.**
Matanuska Electric Association	
Company Name	**Date**

When did you discover the Excess Emissions/Permit Deviation?

Date: ______ / ______ / __________ Time: ______ :/ ______

When did the event/deviation occur?

Begin Date: _____ / _____ / ________ Time: ______ : _______ (Use 24-hr clock.)
End Date ______ / _____ / _________ Time: ______ : _______ (Use 24-hr clock.)

What was the duration of the event/deviation? ____ : ____ (hrs:min) or _________ days
(total # of hrs, min, or days, if intermittent then include only the duration of the actual emissions/deviation)

Reason for Notification: (please check only 1 box and go to the corresponding section)

☐ Excess Emissions – Complete Section 1 and Certify

☐ Deviation from Permit Condition – Complete Section 2 and Certify

☐ Deviations from COBC, CO, or Settlement Agreement – Complete Section 2 and Certify

Section 1. Excess Emissions

(a) Was the exceedance: ☐ Intermittent or ☐ Continuous

(b) Cause of Event (Check one that applies):

☐ Start Up/Shut Down ☐ Natural Cause (weather/earthquake/flood)

☐ Control Equipment Failure ☐ Schedule Maintenance/Equipment Adjustment

☐ Bad Fuel/Coal/Gas ☐ Upset Condition ☐ Other ____________________

(c) Description
Describe briefly, what happened and the cause. Include the parameters/operating conditions exceeded, limits, monitoring data and exceedance.

(d) Emissions Units Involved:
Identify the emission unit involved in the event, using the same identification number and name <u>as in the permit</u>. Identify each emission standard potentially exceeded during the event and the exceedance.

EU ID	EU Name	Permit Condition Exceeded/Limit/Potential Exceedance

[5] Revised as of August 20, 2008

(e) Type of Incident (please check only one):

☐ Opacity ______ % ☐ Venting ________ gas/scf ☐ Control Equipment Down

☐ Fugitive Emissions ☐ Emission Limit Exceeded ☐ Other ______________

☐ Marine Vessel Opacity ☐ Flaring ______________________

(f) Unavoidable Emissions:

Do you intend to assert that these excess emissions were unavoidable? ☐ Yes ☐ No

Do you intend to assert the affirmative defense of 18 AAC 50.235? ☐ Yes ☐ No

Certify Report (Go to end of form.)

Section 2. Permit Deviations

(a) Permit Deviation Type (check only one box, corresponding with the section in the permit):

☐ Emission Unit-Specific

☐ Generally Applicable Requirements

☐ Failure to Monitor/Report

☐ Reporting/Monitoring for Diesel Engines

☐ General Source Test/Monitoring Requirements

☐ Recordkeeping Failure

☐ Recording/Reporting/Compliance Certification

☐ Insignificant Emission Unit

☐ Standard Conditions Not Included in the Permit

☐ Stationary Source Wide

☐ Other Section: ______________________________ (Title of section and section number of your permit).

(b) Emission Unit Involved:

Identify the emission unit involved in the event, using the same identification number and name as in the permit. List the corresponding permit conditions and the deviation.

EU ID	EU Name	Permit Condition/ Potential Deviation

(c) Description of Potential Deviation:
Describe briefly what happened and the cause. Include the parameters/operating conditions and the potential deviation.

(d) Corrective Actions:
Describe actions taken to correct the deviation or potential deviation and to prevent future recurrence.

Certification:
Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Printed Name: ______________________ Title: ______________________ Date: _________
Signature: _________________________ Phone Number: ____________________________

NOTE: *This document must be certified in accordance with 18 AAC 50.345(j)*

To Submit this Report:

Fax to: 907-451-2187
Or
Email to: DEC.AQ.Airreports@alaska.gov
If faxed or emailed, the report must be certified within the Operating Report required for the same reporting period.
Or
Mail to: ADEC
Air Permits Program
610 University Avenue
Fairbanks, AK 99709-3643
Or
Phone Notification: 907-451-5173
Phone notifications require a written follow-up report.
Or
Submission of information contained in this report can be made electronically at the following website:
https://myalaska.state.ak.us/deca/air/airtoolsweb/
If submitted online, report must be submitted by an authorized E-Signer for the stationary source.

SLR