Alaska Department of Environmental Conservation

Amendments to:

State Air Quality Control Plan

Vol. III: Appendices

Public Review Draft

March 17, 2014

Sean Parnell, Governor

Larry Hartig, Commissioner

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The State of Alaska's State Air Quality Control Plan Volume III (Appendix to Volume II, Section II of this plan) is amended by removing the following regulations:

- 18 AAC 50 Air Quality Control as amended through Insert Date; and

replacing them with the following regulations currently under public review and comment:

- 18 AAC 50 Air Quality Control as amended through *{effective date of the regulations}*.

The State of Alaska's State Air Quality Control Plan Volume III (Appendix to Volume II, Section II of this plan) is amended by adding the following document and its two attachments:

- Clean Air Act Section 110 Infrastructure Certification for the 2010 1-hour Nitrogen Dioxide (NO_2) and 1-hour Sulfur Dioxide (SO_2) National Ambient Air Quality Standards;

- Attachment #1- Alaska Administrative Code Title 2- Administration; Chapter 50- Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulations of Lobbying; Article 1 – Public Official Financial Disclosure (2 AAC 50.010- 2 AAC 50.200); and

- Attachment #2- Alaska Administrative Code Title 9 – Law; Chapter 52 – Executive Branch Code of Ethics (9 AAC 52.010 – 9 AAC 52.990).

Volume II, Section III.C: Fairbanks Transportation Control Program, adopted into the State Air Quality Control Plan as of February 22, 2013, is amended as follows:

- Appendix III.C.3 is amended by adding the following document:
    - Sierra Research memorandum, dated November 20, 2012, comparing the current 2005-2015 base year emission inventory to the 2002-2015 base year inventory.

Vol. II, Section III. K: Area-wide Pollutant Control Program for Regional Haze, adopted into the State Air Quality Control Plan as of February 11, 2011, is amended by adding the following appendix:

- Appendix III.K.6 Best Available Retrofit Technology (BART) Documentation.

Placeholder for:

ALASKA ADMINISTRATIVE CODE
TITLE 18- DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Chapter 50. Air Quality Control

as amended through {*Effective Date of Regulations*}.

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ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Vol. III: Appendices

Clean Air Act Section 110 Infrastructure Certification Documentation

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Attachments

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Attachment 2. Alaska Administrative Code Title 9- Law, Chapter 52. Executive Branch Code of Ethics.

List of Acronyms & Abbreviations

AAC	Alaska Administrative Code
AMQA	Air Monitoring & Quality Assurance
CAA	Clean Air Act
CBJ	City & Borough of Juneau
CFR	Code of Federal Regulations
DAQ	Division of Air Quality
DEC	Department of Environmental Conservation
EPA	Environmental Protection Agency
FNSB	Fairbanks North Star Borough
MOA	Municipality of Anchorage
MOU	Memorandum of Understanding
NAAQS	National Ambient Air Quality Standard
NEI	National Emissions Inventory
NNSR	Nonattainment New Source Review
NO	Nitrogen Oxide
NOy	Total Reactive Nitrogen

NOx	Nitrous Oxide
NO_2	Nitrogen Dioxide
NSR	New Source Review
PM-2.5	Fine Particulate Matter
ppm	Parts Per Million
PSD	Prevention of Significant Deterioration
§	Section
SIL	Significant Impact Level
SIP	State Implementation Plan
SOx	Sulfur Oxides
SO_2	Sulfur Dioxide
tpy	Tons per Year
US	United States

Alaska's Compliance with Clean Air Act Section 110 Requirements

The Clean Air Act (CAA) requires that states make State Implementation Plan (SIP) submissions to the United States (US) Environmental Protection Agency (EPA) which meet the basic requirements of CAA sections (§) 110 a, 1 and 2, A through M within three years after promulgation of any new or revised National Ambient Air Quality Standard (NAAQS). The purpose of this document is to demonstrate that the Alaska Department of Environmental Conservation (DEC) has the statutory and regulatory authority to implement, maintain and enforce the requirements of CAA §110 a, 1 and 2, A-M, also known as the "infrastructure requirements".

Alaska's statutes give DEC the authority to promulgate regulations for implementing and enforcing the CAA and other legislation. These regulations are established within Alaska Administrative Code (AAC), Title 18. Environmental Conservation:

- AAC Title 18. Environmental Conservation:
  - Chapter 50. Air Quality Control (18 AAC 50.005-50.990);
  - Chapter 52. Emissions Inspection and Maintenance Requirements for Motor Vehicles (18 AAC 52.005-18 AAC 52.990);
  - Chapter 53. Fuel Requirements for Motor Vehicles (18 AAC 53.005-53.990); and
  - Chapter 95. Administrative Enforcement (18 AAC 95.010-95.900).

Within DEC, the Division of Air Quality (DAQ) administers the CAA in Alaska via these regulations and Alaska's State Air Quality Control Plan. DEC's authority to act on behalf of the State of Alaska in any matter pertaining to the State Air Quality Control Plan is explicitly stated in the following statute:

- **AS 46.14.030. State air quality plan.** The department shall act for the state in any negotiations relative to the state air quality control plan developed under 42 U.S.C. 7401 - 7671q (Clean Air Act), as amended. The department may adopt regulations necessary to implement the state plan.

The original plan (contained in Volumes I & II) was federally adopted in April 1972.[1] The original plan summarized the state's legal authority to control air pollution and included state and local air pollution control strategies, monitoring, and air episode plans for particulate matter, carbon monoxide and sulfur dioxide. The State Air Quality Control Plan has since been revised and is adopted by reference in Alaska Administrative Code (AAC) in Title 18, Chapter 50, Section 030 (18 AAC 50.030).[2] The State Air Quality Control Plan is a legally enforceable document and is enforced by DEC.

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[1] State of Alaska Air Quality Control Plan, Volumes I & II, adopted April 21, 1972.
[2] State of Alaska Air Quality Control Plan, Volumes II & III, as adopted in 18 AAC 50.030.

Portions of this control plan make up Alaska's State Implementation Plan (SIP) which addresses the requirements of the 1970 Amendments to the CAA (FR August 14, 1971), the CAA Amendments of 1990 and subsequent requirements set out by EPA. Each time EPA approves an amendment to Alaska's State Air Quality Control Plan, those amendments become a part of the federally enforceable SIP. These amendments include Alaska's adoption of new NAAQS and the respective CAA §110 infrastructure certification, as presented in Table 1. DEC updates Table 1 each time a new SIP amendment is adopted to certify Alaska's compliance with the NAAQS and its CAA §110 infrastructure requirements.

Table 1: Alaska's State Air Quality Control Plan CAA §110 Infrastructure Certifications.

NAAQS Element	NAAQS Federal Register Date	NAAQS Federal Register Number	State of Alaska NAAQS Effective Date of Regulation	State of Alaska CAA §110 SIP Certification Effective Date of Regulation	Table Number	Notes
Ozone 8-hour	7/18/97	62 FR 38856	6/21/98	8/1/12	2	
$PM_{2.5}$ annual & 24-hour	7/18/97	62 FR 38652	6/21/98	8/1/12	2	
$PM_{2.5}$ 24-hour	10/17/06	71 FR 61144	4/1/2010	8/1/12	2	Complete except for 110(a)(2)(G).
Ozone 8- hour	3/27/08	73 FR 16436	4/1/2010	8/1/12	2	
Lead	11/12/08	73 FR 66964	4/1/2010	8/1/12	2	
SO_2 1-hour	6/22/10	75 FR 35520	9/17/2011	Insert Date	3	
NO_2 1-hour	2/9/10	75 FR 6474	1/4/2013	Insert Date	3	

DEC demonstrates compliance with the NAAQS infrastructure requirements by submitting a new and separate table for each §110 SIP certification, as shown in Table 1. These tables provide a chronological history of DEC's CAA §110 SIP submittals and include the following: DEC's general statutory and regulatory authority; DEC's specific regulatory authority for a particular NAAQS; Alaska's programs, plans and agreements (e.g., Memoranda of Understanding or Agreement) necessary for the implementation, maintenance and enforcement the NAAQS. DEC has also included **Attachment 1 [**Alaska Administrative Code Title 2- Administration, Chapter 50. Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulation of Lobbying {Article 1- Public Official Financial Disclosure}] and **Attachment 2 [**Alaska Administrative Code Title 9- Law, Chapter 52. Executive Branch Code of Ethics] to demonstrate Alaska's compliance with CAA §110 §110(a)(2)(E)(ii) and the intent of CAA §128 "conflict of interest" phrases. DEC has submitted these existing regulations to meet the intent of CAA §110 (a) (2) (E) and CAA §128 for this CAA §110 certification and for all future CAA §110 certification amendments to the SIP.

Table 2: Alaska's Compliance with CAA §110 Infrastructure Requirements for the 1997 & 2006 PM2.5 NAAQS; 1997 & 2008 Ozone NAAQS and 2008 Lead NAAQS.

CAA §110 Infrastructure Element	How Infrastructure Requirement is Addressed in Alaska's SIP
§110(a) (2)(A) Emission limits & other control measures	**Alaska Administrative Code (AAC), Title 18 Environmental Conservation, Chapter 50 Air Quality Control** DEC has promulgated regulations to implement and enforce the NAAQS and other emission limitations. These regulations include statewide ambient air quality standards, major and minor permits, transportation conformity and fees, among others which are found in the following articles of AAC Title 18 Environmental Conservation, Chapter 50. Air Quality Control: • Article 1. Ambient Air Quality Standards (18 AAC 50.005 - 18 AAC 50.110); • Article 2. Program Administration (18 AAC 50.200 - 18 AAC 50.250); • Article 3. Major Stationary Source Permits (18 AAC 50.300 - 18 AAC 50.390); • Article 5. Minor Permits (18 AAC 50.502 - 18 AAC 50.560); • Article 7. Conformity (18 AAC 50.700 – 18 AAC 50.735); and • Article 9. General Provisions (18 AAC 50.900 – 18 AAC 50.990). On April 1, 2010, the State of Alaska adopted the 2006 PM2.5 24-hour and annual NAAQS; the 2008 ozone 8-hour NAAQS; and the 2008 lead NAAQS into 18 AAC 50, Article 1. Alaska's current ambient air quality standards are found in Article 1 at **18 AAC 50.010**. [3] Alaska's air quality designations, classifications and control regions are found in **18 AAC 50.015**. DEC has worked with EPA regarding the PM2.5 non-attainment area boundary for the Fairbanks North Star Borough (FNSB). This boundary was finalized by EPA in November 2009 and became effective on December 14, 2009. DEC has formally commenced SIP planning activities, in cooperation with the FNSB, to update the SIP to include the FNSB PM2.5 non-attainment area and additional control measures, air monitoring and emission

[3] The Division of Air Quality's current regulations are found in **Title 18 AAC 50 Air Quality Control**, as amended through Insert Date; refer to http://www.dec.state.ak.us/regulations/pdfs/18%20AAC%2050.pdf

	inventory work for PM2.5. Alaska will have three years from the above designation date to submit a SIP attainment demonstration and adopt regulations to ensure that this area will attain the 2006 PM2.5 NAAQS within five years. There are no ozone or lead nonattainment areas in Alaska at the present time (winter 2012).
§110(a) (2)(B) Ambient air quality monitoring & data analysis system	DEC's statutory and regulatory authority to conduct ambient air monitoring investigations is found in **AS 46.03.020 (5)**, **AS 46.14.180** and **18 AAC 50.201**. On April 1, 2010, the State of Alaska adopted into Articles 1 and 2 of 18 AAC 50 the following 40 CFR Part 50 reference and interpretation methods for the 2006 PM2.5 24-hour and annual NAAQS; the 2008 ozone 8-hour NAAQS; and the 2008 lead NAAQS: • Appendix G: Reference Method for the Determination of Lead in Suspended Particulate Matter Collected From Ambient Air; • Appendix L: Reference Method for the Determination of Fine Particulate Matter as PM2.5 in the Atmosphere; • Appendix N: Interpretation of the National Ambient Air Quality Standards for Particulate Matter;

	• Appendix P: Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone; • Appendix Q: Reference Method for the Determination of Lead in Particulate Matter as PM10 Collected From Ambient Air; and • Appendix R: Interpretation of the National Ambient Air Quality Standards for Lead. The Municipality of Anchorage (MOA) and Fairbanks North Star Borough (FNSB) both have a Memorandum of Understanding (MOU) with DEC to operate air quality control programs in their respective jurisdictions.[4,5] DEC's Air Non-Point Mobile Source Program (ANPMS) and Air Monitoring & Quality Assurance Program (AMQA) work with the MOA and FNSB to prepare Alaska's annual ambient air monitoring network plan.[6] Alaska's ambient air monitoring network plan includes appropriate monitoring provisions and procedures to comply with the PM2.5 NAAQS monitoring requirements within the FNSB PM2.5 non-attainment area. Ambient PM2.5 monitoring data are collected by the MOA, the FNSB and DEC. Both the MOA and FNSB report their ambient air data to DEC on a quarterly basis. DEC collects PM2.5 data for the City and Borough of Juneau (CBJ) and the Matanuska-Susitna Valley and reports these data to EPA on a quarterly basis. Ambient air quality and meteorological data that are collected for Prevention of Significant Deterioration (PSD) purposes by permitted stationary sources are reported to DEC on a quarterly and annual basis.
§110(a)(2)(B) (continued)	DEC's revised "*Quality Assurance Project Plan for the State of Alaska Air Monitoring & Quality Assurance Program*" [7] was adopted by reference into the State Air Quality Control Plan under **18 AAC 50.030(4)** on October 29, 2010. This manual includes the appropriate, federally referenced ambient air quality monitoring and analysis procedures for PM2.5, ozone and lead. As described in this plan, validated State & Local Air Monitoring Stations (SLAMS), and Special Purpose Monitoring (SPM) ambient air quality monitoring data are reported to the AMQA's database manager. This person verifies the data, and electronically reports these data to EPA through the Air Quality System (AQS) on a quarterly basis.

[4] MOU between DEC and Municipality of Anchorage for Air Quality Control, signed June 30, 2011.
[5] MOU between DEC and Fairbanks North Star Borough for Air Pollution Control, dated January 26, 2010.
[6] Division of Air Quality's "Alaska's 2012 Air Monitoring Plan" www.dec.state.ak.us/air/am/am_airmonplan.htm.
[7] Division of Air Quality's "Quality Assurance Project Plan for the State of Alaska Air Monitoring & Quality Assurance Program" http://www.dec.state.ak.us/air/doc/ADEC_AMQA_QAPP_23FEB10-final.pdf

	Ozone Monitoring: Currently (winter 2012), there are no nonattainment areas for ozone or lead in Alaska. Existing, ambient air quality data with regards to ozone and lead in Alaska are scarce. MOA, in conjunction with DEC, began monitoring for ozone at two sites starting in April 2010.[8] Ozone monitoring occurred in 2010 and 2011, April through September, at the "Garden" site located in downtown Anchorage less than 1 mile south of the Merrill Field airport. Ozone monitoring was also performed at the "Parkgate" site, located in Eagle River, during the 2010 ozone monitoring season (April through September). The ozone monitoring program was discontinued at the "Parkgate" site after review of the seasonal results. The ozone monitoring equipment was moved to Wasilla, located in the Matanuska-Susitna Valley, for the 2011 monitoring season. **Lead Monitoring**: Source specific, ambient, lead monitoring related to operations at the Red Dog Mine, located in Noatak, has been initiated by DEC to address federal lead monitoring requirements. Lead monitoring in Noatak occurred from January 2010 through June 2010; and then from July through August 2011. These monitoring efforts are scheduled to start again in the spring of 2012. Also, MOA, , in conjunction with DEC and EPA, began monitoring for lead, on October 18, 2011, at the Merrill Field airport to determine if lead emissions from aviation gasoline used by piston-engine aircraft are a concern for local residents. Merrill Field airport is the largest general aviation airport in Alaska and is located within the Municipality of Anchorage. EPA is considering regulating lead in aviation gasoline.**[8]**
§110(a) (2)(C) Program to enforce control measures, regulate modification & construction of stationary sources and a permit program	DEC's statutory authority to regulate stationary sources via an air permitting program is established in **AS 46.14 Air Quality Control**, Article 01, General Regulations and Classifications; and Article 02, Emission Control Permit Program. DAQ's Air Permits Program issues air discharge permits for stationary sources according to the following regulations: • Construction permit for new or modified construction projects (18 AAC 50.302); • Prevention of significant deterioration (PSD) permit (18 AAC 50.306); • Non-attainment area major stationary source permit (18 AAC 50.311); and • Minor Permits (18 AAC 50 Article 5).

[8] EPA's "Advance Notice of Proposed Rulemaking on Lead Emissions from Piston-Engine Aircraft Using Leaded Aviation Gasoline", dated April 28, 2010.

§110(a)(2)(C) (continued)	Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. Amendments to Alaska's PSD/NSR program were more recently approved by EPA on August 14, 2007 [72 FR 45378] and February 9, 2011 [76 FR 7116]. On August 3, 2011, DEC adopted the PM2.5 Significant Impact Levels (SILs) as published in the Federal Register on October 20, 2010 [75 FR 64902]; DEC also adopted the PM2.5 source testing requirements as specified in Appendix M to 40 C.F.R. Part 51. The PM2.5 SILs and source test requirement regulations became effective on September 17, 2011. A copy of these regulations and SIP amendment were forwarded to EPA Region 10 via a transmittal letter dated October 17, 2011. Alaska's approved PSD/NSR program implements the 1997 and 2008 ozone 8-hour NAAQS and relevant requirements of the Phase II ozone implementation rule as required in 69 FR 23951 (April 30, 2004) and 70 FR 71612 (November 29, 2005). Standard and compliance conditions for stationary sources are found in 18 AAC 50.345. Owner requested limits (ORL) and plant-wide applicability limitations (PALs) are regulated according to 18 AAC 50.508, 18 AAC 50.540, and 18 AAC 50.542. Minor permit regulations requiring analysis of ambient air quality are found at 18 AAC 50.542(c). Regulations governing air pollution prohibitions are found at **18 AAC 50.045, 18 AAC 50.110, and 18 AAC 50.345(c)**. A violation of these prohibitions or any permit condition can result in civil actions (**AS 46.03.760**), administrative penalties (**AS 46.03.761**), or criminal penalties (**AS.03.790**). Regulations pertaining to compliance orders and enforcement proceedings are found in **18 AAC Chapter 95 Administrative Enforcement**.
§110(a)(2)(D)(i)(I) and (II) Interstate transport and international pollution abatement	EPA originally approved the actions of DEC to address the provisions of the CAA **§** 110(a)(2)(D)(i)&(ii) regarding Alaska Interstate Transport of Pollution for the 1997 ozone 8-hour NAAQS; and for the 1997 PM2.5 NAAQS on October 15, 2008 [73 FR 60955]. DEC submitted Alaska's Interstate Transport of Pollution SIP for the 2006 PM2.5 24-hour and annual NAAQS; and for the 2008 ozone 8-hour NAAQS in conjunction with Alaska's Open Burn SIP and Alaska's Regional Haze SIP via a transmittal letter to EPA Region 10, dated March 29, 2010. These SIP amendments were intended to meet the regional haze program requirements found in 40 CFR §51.308; and also addressed Alaska's "Finding of Failure to Submit State Implementation Plans Required by the 1999 Regional Haze Rule" [74 FR 2392,

§110(a)(2)(D)(i)(I) and (II) (continued)	January 15, 2009]. DEC submitted Alaska's Interstate Transport of Pollution SIP for the 2008 Lead NAAQS to EPA via a transmittal letter to EPA Region 10, dated July 9, 2012. Compliance with CAA §110(a)(2)(D)(i)(I)&(II) requirements is pending EPA's final approval of Alaska's ozone, PM2.5 and lead Interstate Transport SIP amendments. DEC concludes that the written SIP amendments sufficiently demonstrate that emissions from Alaska do not significantly contribute to nonattainment or interfere with maintenance of the 1997 or 2008 ozone NAAQS; the 1997 or 2006 PM2.5 NAAQS; or the 2008 lead NAAQS in another state; or interfere with measures required to be included in the SIP for any other state to prevent significant deterioration of air quality or to protect visibility. Alaska is not subject to the "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone" also called the "Interstate Air Quality Rule" [see 69 FR 4566, January 30, 2004].
§110(a)(2)(D)(ii) Interstate transport and interstate & international pollution abatement "… insuring compliance with the applicable requirements of CAA § 126 and 115".	Compliance with CAA §110(a)(2)(D)(ii) requirements is satisfied through the implementation of Alaska's PSD/NSR program originally approved by EPA on February 16, 1995 [60 FR 8943] and more recently approved by EPA on August 14, 2007 [72 FR 45378] and February 9, 2011 [76 FR 7116]. Alaska's approved PSD/NSR program implements the 1997 and 2008 ozone 8-hour NAAQS and relevant requirements of the Phase II ozone implementation rule as required in 69 FR 23951 (April 30, 2004) and 70 FR 71612 (November 29, 2005). For PM2.5, DEC has moved forward to implement PM2.5 requirements within its PSD program. Initially, DEC relied on EPA's interim guidance calling for the use of PM10 as a surrogate for PM2.5. DEC recently adopted the PM2.5 SILs and also adopted the PM2.5 source testing requirements as specified in Appendix M to 40 C.F.R. Part 51. The PM2.5 SILs and source test requirement regulations became effective on September 17, 2011. A copy of these regulations and SIP amendment were forwarded to EPA Region 10 via a transmittal letter dated October 17, 2011.
§110(a)(2)(E)(i) Adequate personnel, funding and authority to carry out plan	DEC has implemented CAA requirements and the State Air Quality Control Plan since its inception in 1972. DEC's statutory and regulatory authorities to implement and enforce the State of Alaska's Air Quality Control Plan are found at **AS 46.14.030** and **18 AAC 50.030**, respectively. The State of Alaska has adequate personnel, funding and the authority to implement the 1997 and 2008 ozone NAAQS; the 1997 and 2006 PM2.5 NAAQS; and the 2008 lead NAAQS. The statutory authority for establishing local air pollution control programs is found in **AS 46.14.400—**Local Air Quality Control Programs. Where local control programs are relied upon to meet

	SIP requirements, DEC insures that the local program has adequate resources and documents this in the appropriate SIP sections.
§110(a)(2)(E)(ii) **Comply with state boards**	Alaska's regulations meeting the intent of CAA §110(a) (2) (E) and CAA §128 "conflict of interest" phrases are found in **Attachment 1**- AAC Title 2- Administration; Chapter 50- Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulations of Lobbying - Article 1- Public Official Financial Disclosure (**2 AAC 50.010- 2 AAC 50.920**) and **Attachment 2-**Title 9- Law; Chapter 52- Executive Branch Code of Ethics (**9 AAC 52.010-9 AAC 52.990**). These existing regulations are adopted into the State Air Quality Control Plan and are included as attachments to this SIP submittal. DEC is submitting these regulations to meet the intent of CAA §110 (a) (2) (E) and CAA §128 for this CAA §110certification and for all future CAA §110 certification amendments to the SIP.
§110(a)(2)(E)(ii) (continued)	There are no state air quality boards in Alaska, however, the DEC Commissioner, as an appointed official and the head of an executive agency, is required to file a financial disclosure statement annually by March 15th of each year with the Alaska Public Offices Commission (APOC). These disclosures are publically available through APOC's Anchorage office. Alaska's Public Officials Financial Disclosure Forms and Internet links to Alaska's financial disclosure regulations can be found at the APOC website: http://doa.alaska.gov/apoc/home.html .

§110(a)(2)(E)(iii) oversee local & regional government/agencies	As a matter of policy, DEC encourages the development of strong local air quality control programs. DEC provides technical assistance and regulatory oversight to the MOA, FNSB and other local jurisdictions to ensure that the State Air Quality Control Plan and SIP objectives are satisfactorily carried out. As mentioned, DEC has an MOU with the MOA and FNSB which allows them to operate air quality control programs in their respective jurisdictions. The South Central Clean Air Authority has been established to aid the MOA and the Matanuska-Susitna Borough in pursuing joint efforts to control emissions and improve air quality in the air-shed common to the two jurisdictions. DEC has formally commenced SIP planning activities, in cooperation with the FNSB, to update Alaska's SIP to include the FNSB PM2.5 non-attainment area and additional control measures, air monitoring and emission inventory work for PM2.5. Alaska will have three years from the designation date (December 14, 2009) to submit a SIP attainment demonstration and adopt regulations to ensure that this area will attain the 2006 PM2.5 NAAQS within five years. The MOU may also have to be updated to reflect the changes made to the SIP.

110(a)(2)(F) Stationary source emissions monitoring and reporting system	DEC's general statutory authority to regulate stationary sources via an air permitting program is established in **AS 46.14 Air Quality Control**, Article 01, General Regulations and Classifications; and Article 02, Emission Control Permit Program. Alaska's statutes regarding stationary source permit reporting requirements, completeness determinations, administrative actions, and stack source monitoring requirements are found at **AS 46.140** through **AS 46.14.180**. DEC's regulatory authority to determine compliance with these statutes is found in **18 AAC 50.200 Information requests**; and **18 AAC 0.201 Ambient air quality investigations**. As stated previously, on April 1, 2010, the State of Alaska adopted into **18 AAC 50, Articles 1 and 2**, the appropriate 40 CFR Part 50 reference and interpretation methods for the 2006 24-hour and annual PM2.5; the 2008 8-hour ozone; and the 2008 lead NAAQS. Monitoring protocols and test methods for stationary sources that have been adopted by reference in the State Air Quality Control Plan are found at **18 AAC 50.030**. Other documents, procedures and test methods adopted by reference, including the federal reference and interpretation methods for the new NAAQS, are found at **18 AAC 50.035**. Federal standards adopted by reference are found at **18 AAC 50.040**. On August 3, 2011, DEC adopted the PM2.5 source testing requirements into **18 AAC 50.220(c)**, as required in Appendix M to 40 C.F.R. Part 51. Monitoring, reporting, and record keeping requirements for permitted stationary sources are found in the standard permit conditions for construction and operating permits at **18 AAC 50.345**. Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943] and more recently approved on August 14, 2007 [72 FR 45378] and February 9, 2011 [76 FR 7116]. Alaska's approved program implements the 1997 and 2008 8-hour ozone NAAQS and relevant requirements of the Phase II ozone implementation rule as required in 69 FR 23951 (April 30, 2004) and 70 FR 71612 (November 29, 2005). For PM2.5, DEC has moved forward to implement PM2.5 requirements within its PSD program. Initially, DEC has relied on EPA's interim guidance calling for the use of PM10 as a surrogate for PM2.5. DEC recently adopted (August 3, 2011) the PM2.5 SILs; DEC also adopted the PM2.5 source testing requirements. The PM2.5 SILs and source test requirement regulations became effective September 17, 2011. A copy of these regulations and SIP amendment were forwarded to EPA Region 10 via a transmittal letter dated October 17, 2011. Ambient air

	quality and meteorological data that are collected for PSD purposes by stationary sources are reported to DEC on a quarterly and annual basis.

§110(a)(2)(G) **Authority to declare air pollution emergency and notify public**	DEC's regulatory authority to act during air episodes is found at 18 AAC 50.245. This authority is promulgated under the following statutes: **AS 46.03.020**; **AS 46.03.820**; **AS 46.14.010**; **AS 46.14.020**, **AS 46.14.030** and **46.14.540**. At the present time (winter 2012), DEC is working to update its regulations found at **18 AAC 50.245 Table 6 "Concentrations Triggering an Air Episode**" to include provisions at least as stringent as (or more stringent than) EPA's recommended, interim, PM2.5 Significant Harm Levels (SHLs) for triggering an Air Alert, Air Warning and Air Emergency. Also in this regulations package, DEC plans to amend **18 AAC 50.245(a), (b)** and **(c)** to give local air quality control programs, recognized by the State of Alaska, the authority to declare air quality episodes and advisories and to take action. Release of these regulations for public review is pending approval within the Department. Following public comment and legal review, these provisions will be finalized and submitted to EPA for action and inclusion in Alaska's federally approved SIP. In the interim, DEC can and does issue air advisories under **18 AAC 50.245** to address PM2.5 episodes when air quality conditions warrant action. The three major municipalities in Alaska (MOA, FNSB, and CBJ) also have ordinances, codes, or regulations that enable them to declare emergencies in the case of poor air quality due to forest fires, volcanoes, wood smoke or other air quality problem. DEC will work with the FNSB to develop a Emergency Episode Contingency Plan for PM2.5 for the FNSB nonattainment area as outlined in 40 CFR Subpart H- Prevention of Air Pollution Emergency Episodes, and in Appendix L to Subpart 51 "Example Regulations for Prevention of Air Pollution Emergency Episodes". DEC personnel remain in close contact with each municipality when an air emergency is declared, assisting with air monitoring and analysis, and implementing safety and control measures, as needed.
§110(a)(2)(H) **Future SIP Revisions**	DEC's statutory authority to adopt regulations in order to implement the CAA and the state air quality control program is found in **AS 46.03.020(10) (A)**, and **AS 46.14.010(a)**. DEC's regulatory authority to implement any provision of the CAA is found in 18 AAC 50.010. DEC strives to establish regulations and update Alaska's SIP in a timely fashion as new NAAQS are promulgated by EPA.

§110(a)(2)(J) **§ 121 consultation**	DEC's statutory authority to consult and cooperate with officials of local governments, state and federal agencies, and non-profit groups is found in **AS 46.030.020 (3), (8)**. Municipalities and local air quality districts seeking approval for a local air quality control program shall enter into a cooperative agreement with DEC according to **AS 46.14.400(d)**. DEC can adopt new CAA regulations only after a public hearing (**AS 46.14.010(a)**).
§110(a)(2)(J) **Section 127 public notification**	Public notice and public hearing regulations for SIP submittals and air quality discharge permits are found at **18 AAC 15.050** and **18 AAC 15.060**.
§110(a)(2)(J) **PSD & visibility protection**	Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943] and more recently approved on August 14, 2007 [72 FR 45378] and February 9, 2011 [76 FR 7116]. Alaska's approved program implements the 1997 and 2008 8-hour ozone NAAQS and relevant requirements of the Phase II ozone implementation rule as required in 69 FR 23951 (April 30, 2004) and 70 FR 71612 (November 29, 2005). For PM2.5, DEC has moved forward to implement PM2.5 requirements within its PSD program. Initially, DEC has relied on EPA's interim guidance calling for the use of PM10 as a surrogate for PM2.5. DEC recently adopted (August 3, 2011) the PM2.5 SILs; DEC also adopted the PM2.5 source testing requirements. The PM2.5 SILs and source test requirement regulations became effective September 17, 2011. A copy of these regulations and SIP amendment were forwarded to EPA Region 10 via a transmittal letter dated October 17, 2011. DEC submitted Alaska's Regional Haze SIP and Open Burn SIP in conjunction with Alaska's Interstate Transport of Pollution SIP for the 2006 PM2.5 NAAQS and for the 2008 ozone NAAQS via a transmittal letter to EPA Region 10, dated March 29, 2010. These SIP amendments were intended to meet the regional haze program requirements found in 40 CFR §51.308; and also addressed Alaska's "Finding of Failure to Submit State Implementation Plans Required by the 1999 Regional Haze Rule" (74 FR 2392, January 15, 2009). Compliance with CAA Title 1, Part C requirements is pending EPA's final approval of Alaska's Regional Haze,

	Open Burn, and Interstate Transport (ozone, PM2.5) SIP submissions. DEC concludes that there are no new visibility protection obligations under CAA §110(a) (2) (J) as a result of the 2008 lead NAAQS. Alaska is not subject to the “Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone” also called the “Interstate Air Quality Rule” [see 69 FR 4566, January 30, 2004].
§110(a)(2)(K) **Air quality modeling/data**	Air quality modeling by DEC is conducted under **18 AAC 50.215(b)**, ambient air quality analysis methods. Estimates of ambient concentrations and visibility impairment must be based on applicable air quality models, databases, and other requirements specified in the EPA's Guideline on Air Quality Models adopted by reference in **18 AAC 50.040(f)**. This regulation allows some provisions to exclude concentrations attributable to temporary construction activity for a new or modified source, or to new sources outside the United States. DEC is currently (winter 2012) updating the baseline dates and maximum allowable increases for PM2.5, found in 18 AAC 50.020, to account for the 2006 PM2.5 NAAQS revisions. Pending Department approval, it is anticipated that the PM2.5 baseline date and maximum allowable increase regulation revisions will be released for public notice during the winter of 2012. These regulations will be finalized and submitted to EPA for action and inclusion in Alaska’s federally approved SIP following public comment and legal review.
§110(a)(2)(L) **Major Stationary source permitting fees**	DEC’s statutory authority to assess and collect permit fees is established in **AS 46.14.240** and **AS 46.14.250**. The permit fees for permitting major and minor stationary sources are assessed and collected by the Air Permits Program according to **18 AAC 50 Article 4. User Fees** (**18 AAC 50.400 through 18 AAC 50.430**). The Air Permits Program is required to evaluate emission fee rates at least every four years, and provide a written evaluation of the findings (**AS 46.14.250(g)**; **18 AAC 50.410**). The Division’s most recent emission fee evaluation report was completed in October 2010. The Division’s next emission fee review is scheduled for 2014.

§110(a)(2)(M) Consultation/Participation by affected local entities	DEC has the statutory authority to consult and cooperate with officials and representatives of any organization in the state; and persons, organization, and groups, public and private using, served by, interested in, or concerned with the environment of the state (**AS 46.03.020 (3) (A)(B)**).

Table 3: Alaska's Compliance with CAA §110 Infrastructure Requirements for the 2010 Nitrogen Dioxide and Sulfur Dioxide 1-hour NAAQS.

CAA §110 Infrastructure Element	How Infrastructure Requirement is Addressed in Alaska's SIP
§110(a)(2)(A) Emission limits & other control measures	DEC has promulgated regulations to implement and enforce the NAAQS and other emission limitations. These regulations include statewide ambient air quality standards, major and minor permits, transportation conformity and fees, among others which are found in the following articles of Alaska Administrative Code (AAC) **Title 18 Environmental Conservation, Chapter 50. Air Quality Control**: • Article 1. Ambient Air Quality Standards (18 AAC 50.005 - 18 AAC 50.110); • Article 2. Program Administration (18 AAC 50.200 - 18 AAC 50.250); • Article 3. Major Stationary Source Permits (18 AAC 50.300 - 18 AAC 50.390); • Article 5. Minor Permits (18 AAC 50.502 - 18 AAC 50.560); • Article 7. Conformity (18 AAC 50.700 – 18 AAC 50.735); and • Article 9. General Provisions (18 AAC 50.900 – 18 AAC 50.990). • **Article 1. Ambient Air Quality Standards** (18 AAC 50.005 - 18 AAC 50.110) - Alaska's current ambient air quality standards, as amended through Insert Date, are found at: http://dec.alaska.gov/commish/regulations/index.htm

§110(a)(2)(A) (continued)	• **18 AAC 50.010(2) -** The State of Alaska adopted the 2010 1-hour SO_2 NAAQS on August 3, 2011; this regulation became effective on September 17, 2011. • **18 AAC 50.010(5)** - The State of Alaska adopted the 2010 1-hour NO_2 NAAQS on December 5, 2012; this regulation became effective on January 4, 2013. • **18 AAC 50.015. Air quality designations, classifications, and control regions -** There are no NO_2 or SO_2 non-attainment areas in Alaska at the present time (summer/fall 2013). EPA officially designated all of Alaska "unclassifiable" with respect to the 1-hour NO_2 on June 29, 2011. DEC recommended that all areas within the borders of Alaska be designated as "unclassifiable" in regards to the 1-hour SO_2 NAAQS in a letter to EPA Region 10, dated June 2, 2011. DEC anticipates that all of Alaska will be designated by EPA as "unclassifiable" in regards to the 1-hour SO_2 NAAQS in the near future. • **18 AAC 50.040. Federal standards adopted by reference-** The Prevention of Significant Deterioration (PSD) of Air Quality regulations in 40 C.F.R. 51.166 and 40 C.F.R. 52.21 are adopted in **18 AAC 50.040(h)** as of January 4, 2013. • **18 AAC 50.055. Industrial processes and fuel-burning equipment -**includes SO_2 emission limits for fuel burning equipment and petroleum refineries. • **18 AAC 50.060. Pulp mills -**includes SO_2 emission limits for pulp mills in Alaska. • **Article 2. Program Administration** (18 AAC 50.200-18 AAC 50.260) • **18 AAC 50.260 Guidelines for best available retrofit technology under the regional haze rule-** DEC's regulations for best available retrofit technology (**BART**) under the regional haze rule are found at **18 AAC 50.260**. • **Article 3. Major Stationary Source Permits** (18 AAC 50.300-18 AAC 50.390) • **18 AAC 50.302 Construction Permits**.

	• **18 AAC 50.306 Prevention of Significant Deterioration Permits** • **18 AAC 50.345 Construction and Operating Permits: Standard Permit Conditions** • **Article 5. Minor Permits** (18 AAC 50.502 - 18 AAC 50.560) • **18 AAC 50.508 Minor Permits Requested by the Owner or Operator** • **18 AAC 50.540 Minor Permit: Application** • **18 AAC 50.542 Minor Permit Review and Issuance** • **18 AAC Chapter 53 Fuel Requirements for Motor Vehicles**- requirements for oxygenated fuel to reduce NOx emissions.
§110(a)(2)(B) Ambient air quality monitoring & data analysis system	DEC's statutory and regulatory authority to conduct ambient air monitoring investigations is found in Alaska Statute (**AS) 46.03.020 (5)**, **AS 46.14.180** and **18 AAC 50.201**. • **Article 1. Ambient Air Quality Standards** (18 AAC 50.005 - 18 AAC 50.110) • **18 AAC 50.030. State air quality plan**- DAQ's *Quality Assurance Project Plan for the State of Alaska Air Monitoring & Quality Assurance Program*[9], as amended through February 23, 2010, is adopted by reference at **18 AAC 50.030(4)**. This manual includes the appropriate, federally referenced ambient air quality monitoring and analysis procedures and data quality objectives for NO_2 and SO_2. As described in this plan, validated State & Local Air Monitoring Stations, and Special Purpose Monitoring ambient air

[9] Division of Air Quality's "**Quality Assurance Project Plan for the State of Alaska Air Monitoring & Quality Assurance Program.**" http://www.dec.state.ak.us/air/doc/ADEC_AMQA_QAPP_23FEB10-final.pdf

	quality monitoring data are reported to the AMQA's database manager who verifies the data, and then electronically reports these data to EPA through the Air Quality System on a quarterly basis. •**18 AAC 50.035 Documents, procedures, and methods adopted by reference-** The most current and federally approved reference (measurement) and interpretation methods for NO_2 and SO_2 are adopted by reference in **18 AAC 50.035(b)(1)**. These reference and interpretation methods are used by DEC in its ambient air quality monitoring program to determine compliance with the NAAQS. • **Article 2. Program Administration** (18 AAC 50.200-18 AAC 50.260) •**18 AAC 50.201. Ambient air quality investigation-** The Municipality of Anchorage (MOA) and Fairbanks North Star Borough (FNSB) both have a Memorandum of Understanding (MOU) with DEC to operate air quality control programs in their respective jurisdictions.[10,11] DAQ's Air Monitoring & Quality Assurance Program (AMQA) coordinates with MOA and FNSB to prepare Alaska's annual ambient air monitoring network plan. *Alaska's 2013-2014 Air Monitoring Network Plan*[12] includes monitoring provisions for nitrogen oxide (NO); total reactive nitrogen (NOy) and SO_2 at one NCORE site located on Pioneer Road in Fairbanks, Alaska. Ambient NO, NOy and SO_2 monitoring data are collected by the FNSB and reported to DEC on a quarterly basis. Related regulations are found in **18 AAC 50.215. Ambient air quality analysis methods** and **18 AAC 50.220 Enforceable test methods.**
§110(a)(2)(C) Program to enforce control measures, regulate modification & construction of stationary sources and a permit program	**Alaska's air pollution prohibitions-**Alaska's regulations governing air pollution prohibitions are found at **18 AAC 50.045, 18 AAC 50.110**, and **18 AAC 50.345(c)**. A violation of these prohibitions or any permit condition can result in civil actions (**AS 46.03.760**), administrative penalties (**AS 46.03.761**), or criminal penalties (**AS.03.790**). Regulations pertaining to compliance orders and enforcement proceedings are found in **18 AAC Chapter 95 Administrative Enforcement**. • **Article 1. Ambient Air Quality Standards** (18 AAC 50.005 - 18 AAC 50.110) **-** DEC recently adopted new baseline areas for NO_2 and SO_2, as defined at **18 AAC 50.020(g)**, which became effective on January 4, 2013. The procedure for determining a baseline concentration of NO_2 or SO2, as established in 40 C.F.R. 52.21(b) (13) was also recently adopted

[10] MOU between DEC and Municipality of Anchorage for Air Quality Control, signed June 30, 2011.
[11] MOU between DEC and Fairbanks North Star Borough for Air Pollution Control, dated January 26, 2010.
[12] ADEC's "**Alaska's 2013-2014 Air Monitoring Network Plan**" www.dec.state.ak.us/air/am/am_airmonplan.htm.

	in **18 AAC 50.020(e)** and became effective on January 4, 2013. EPA's monitoring guidance entitled "Ambient Monitoring Guidelines for the Prevention of Significant Deterioration" is adopted by reference at **18 AAC 50.035(5)**. On February 9, 2011, EPA approved DEC's SIP submittal concerning its PSD and Title V Green House Gas (GHG) permitting programs, as promulgated in 40 C.F.R. 52.22 and 71.13, and adopted by reference in **18 AAC 50.040(h)(21)** and **18 AAC 50.040(j)(9)** with an effective date of March 11, 2011 [76 FR 7116]. As mentioned previously, EPA's *Guideline on Air Quality Models*, Appendix W to 40 CFR Part 51, is adopted by reference in **18 AAC 50.040(f)**. The most recent revision to Appendix W was published on November 9, 2005 [70 FR 68228], wherein EPA adopted AERMOD as the preferred dispersion model. Appendix W, and therefore AERMOD, is also adopted by reference at **18 AAC 50.215(b) (1)** and is used by DEC during its ambient air quality analysis for the prevention of significant deterioration. Ambient air quality and meteorological data that are collected for PSD purposes by permitted stationary sources are reported to DEC on a quarterly and annual basis. DEC's PSD regulations for NO_2 & SO_2 Class I, II & III areas are found in: •**18 AAC 50.020 (a)**. Table 2. Baseline Areas and Dates. •**18 AAC 50.020 (b)**. Table 3. Maximum Allowable Increases. •**18 AAC 50.020 (e)**. Procedure for establishing NO_2 & SO_2 baseline concentration, effective January 4, 2013. •**18 AAC 50.020 (g)**. Baseline areas for NO_2 & SO_2, effective January 4, 2013. •**18 AAC 50.035 (5)**. EPA's "*Ambient Monitoring Guidelines for Prevention of Significant Deterioration*", adopted by reference. •**18 AAC .040 (f)**. EPA's "*Guideline on Air Quality Models*", adopted by reference. •**18 AAC 50.040 (h) (21) & (j) (9)**. PSD & Title V Greenhouse Gas Permitting Program requirements of 40 C.F.R. 52.22 & 40 C.F.R. 71.13 (Enforceable Commitments for Further Actions Addressing the Pollutant Greenhouse Gases), approved by EPA on February 9, 2011 [76 FR 7116].
§110(a)(2)(C) (continued)	• **Article 2. Program Administration** (18 AAC 50.200-18 AAC 50.260)- EPA has not promulgated regulation changes to implement the 1-hour NO_2 and SO_2 NAAQS under the PSD or Nonattainment New Source Review (NNSR) programs found at 40 C.F.R. §50.166. EPA issued draft PSD guidance concerning the implementation

	of the 1-hour NO_2 and SO_2 NAAQS on June 29 and August 23, 2010, respectively.[13,14] EPA's draft implementation guidance recommends that states use an interim 1-hour NO_2 significant impact level (SIL) value of 4 parts per billion (ppb) and an interim 1-hour SO_2 SIL value of 3 ppb. On August 3, 2011, the State of Alaska adopted an SO_2 SIL level of 8 ppb into Table 5 at **18 AAC 50.215(d)**; the SO_2 SIL regulation became effective on September 17, 2011. The State of Alaska adopted an NO_2 SIL level of 8 ppb into Table 5 on December 5, 2012; the NO_2 SIL regulation became effective on January 4, 2013. Also on this date, DEC adopted new regulatory language at **18 AAC 50.215(d)** regarding how to compare modeled impacts to the NO_2 and SO_2 SIL. These regulations are found here: •**18 AAC 50.215(b) (1)**. EPA's AERMOD, adopted by reference. •**18 AAC 50.215 (d)**. Table 5 Significant Impact Levels for NO_2 & SO_2 adopted; new language regarding how to compare modeled impacts to SILs adopted. • **Article 3. Major Stationary Source Permits**- Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. Amendments to DEC's PSD/NSR program were most recently approved by EPA on August 14, 2007 [72 FR 45378] and February 9, 2011 [76 FR 7116]. DEC's PSD/NSR permit program regulations are found here: • **18 AAC 50.306.** Prevention of significant deterioration (PSD) permits. • **18 AAC 50.311.** Nonattainment area major stationary source permits. •**18 AAC 50.326 (e)**. Title V NO_2 & SO_2 insignificant emission rates. • **Article 5. Minor Permits.** • **18 AAC 50.502. Minor permits for air quality protection.** • **18 AAC 50.502 (c) (1) (B); (c) (1) (C) -** NO_2 & SO_2 significant emission rates for minor permitted facilities.

[13] EPA's "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration.", dated June 29, 2010, Stephen D. Page, Director, Office of Air Quality Planning and Standards.

[14] EPA's "Guidance Concerning the Implementation of the 1-hour SO_2 NAAQS for the Prevention of Significant Deterioration.", dated August 23, 2010, Stephen D. Page, Director, Office of Air Quality Planning and Standards.

§110(a)(2)(D)(i)(I) Interstate transport and interstate & international pollution abatement	In accordance with the panel of the U.S. Court of Appeals for the D.C. Circuit opinion, states are not required to submit CAA section 110(a)(2)(D)(i)(I) until the EPA has quantified their obligations under that section. *See EME Homer City generation, L.P. v. EPA, 696 F .3d 7.* Unless the *EME Homer City* decision is reversed or otherwise modified by the Supreme Court, Alaska is not required to submit 110(a)(2)(D)(i)(I) SIPs for the 2010 NO_2 and 2010 SO_2 NAAQS until the EPA has quantified Alaska's obligations under that section for the 2010 NO_2 and 2010 SO_2 NAAQS.
§110(a)(2)(D)(i)(II) Interstate transport and interstate & international pollution abatement	Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. Amendments to DEC's PSD/NSR program were most recently approved by EPA on August 14, 2007 (72 FR 45378) and February 9, 2011 (76 FR 7116). DEC's PSD and New Source Review regulations are found in: • **Article 3. Major Stationary Source Permits** • **18 AAC 50.302** Construction permit for new or modified construction projects. • **18 AAC 50.306** Prevention of significant deterioration permit. • **18 AAC 50.311** Non-attainment area major stationary source permit. • **18 AAC 50.321** Maximum Achievable Control Technology determination. • **18 AAC 50.345** Standard and compliance conditions for stationary sources. • **18 AAC 50.346** Other permit conditions On February 14, 2013, EPA approved Alaska's Regional Haze Plan submitted on April 4, 2011, as meeting the requirements set forth in sections 169A and 169B of the CAA and in 40 CFR 51.308 regarding Regional Haze [78 FR 10546].
§110(a)(2)(D)(ii) Interstate transport and interstate & international pollution abatement	CAA §126(a) directs states to include SIP provisions requiring new or modified sources to notify neighboring states of potential impacts for the sources. Alaska's federally-approved SIP incorporates by reference 40 CFR 51.166(q)(2) at **18 AAC 50.306(b)**, with certain modifications, to describe the public participation procedures for PSD permits including requiring notice to states whose lands may be affected by the emissions of sources subject to PSD. As a result, Alaska's PSD regulations provide for notice consistent with the requirements of EPA's PSD program. Alaska has no pending obligations under sections 115 or 126(b) of the Act.
§110(a)(2)(E)(i) Adequate personnel, funding and authority to carry out plan	DEC has implemented CAA requirements and the State Air Quality Control Plan since its inception in 1972. DEC's statutory and regulatory authorities to implement and enforce the State of Alaska's Air Quality Control Plan are found at **AS 46.14.030** and **18 AAC 50.030**, respectively. Alaska receives CAA §103 and §105 grant funds from EPA and provides state matching funds necessary to carry out Alaska's SIP requirements. The State of Alaska and DEC have adequate personnel, funding and the authority to implement the 2010 1-hour NO_2 and

	SO_2 NAAQS. The statutory authority for establishing local air pollution control programs is found in **AS 46.14.400—Local Air Quality Control Programs**. Where local control programs are relied upon to meet SIP requirements, DEC ensures that the local program has adequate resources and documents this in the appropriate SIP sections.
§110(a)(2)(E)(ii) **Comply with state boards** "… requirements that the state comply with the requirements respecting state boards under section 128, and…"	Alaska's regulations meeting the intent of CAA §110(a) (2) (E) and CAA §128 "conflict of interest" phrases are found in AAC Title 2- Administration; Chapter 50- Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulations of Lobbying (**2 AAC 50.010- 2 AAC 50.920**). Regulations concerning financial disclosure are found in Title 2, Chapter 50, Article 1- Public Official Financial Disclosure. A copy of Article 1 was adopted into the State Air Quality Control Plan, effective date August 1, 2012, and is included as an appendix to Volume II, Section II. Alaska's executive branch ethics regulations are found in Title 9- Law; Chapter 52- Executive Branch Code of Ethics (**9 AAC 52.010-9 AAC 52.990**). These regulations were also adopted into the State Air Quality Control Plan, effective date August 1, 2012, and are included as an appendix to Volume II, Section II. DEC submitted these regulations to meet the intent of CAA §110 (a) (2) (E) and CAA §128 for all future CAA §110 certification amendments to Alaska's SIP. There are no state air quality boards in Alaska, however, the DEC Commissioner, as an appointed official and the head of an executive agency, is required to file a financial disclosure statement annually by March 15th of each year with the Alaska Public Offices Commission (APOC). These disclosures are publically available through APOC's Anchorage office. Alaska's Public Officials Financial Disclosure Forms and Internet links to Alaska's financial disclosure regulations can be found at the APOC website: http://doa.alaska.gov/apoc/home.html .
§110(a)(2)(E)(iii) **oversee local & regional government/agencies**	Statutory authority and requirements for establishing local air pollution control programs are found at **AS 46.14.400 Local Air Quality Control Programs**. As a matter of policy, DEC encourages the development of strong local air quality control programs. DEC provides technical assistance and regulatory oversight to the MOA, FNSB and other local jurisdictions to ensure that the State Air Quality Control Plan and SIP objectives are satisfactorily carried out. As mentioned, DEC has an MOU with the MOA and FNSB which allows them to operate air quality control programs in their

	respective jurisdictions. The South Central Clean Air Authority has been established to aid the MOA and the Matanuska-Susitna Borough in pursuing joint efforts to control emissions and improve air quality in the air-shed common to the two jurisdictions. DEC is collaborating with the FNSB on collecting ambient air quality samples and analyzing them for nitrogen oxide (NO); total reactive nitrogen (NOy) and SO_2 at one NCORE site located on Pioneer Road in Fairbanks, Alaska. Ambient NO, NOy and SO_2 monitoring data will be collected by the FNSB, who will report their ambient air data to DEC on a quarterly basis. These data will be used by the FNSB, DEC and EPA to determine compliance with the 1-hour NO_2 and SO_2 NAAQS.
§110(a)(2)(F) Stationary source emissions monitoring and reporting system	DEC's general statutory authority to regulate stationary sources via an air permitting program is established in **AS 46.14 Air Quality Control**, Article 01, General Regulations and Classifications; and Article 02, Emission Control Permit Program. Alaska's statutes regarding stationary source permit reporting requirements, completeness determinations, administrative actions, stack source monitoring requirements and issuing a public notice are found at **AS 46.14.140** through **AS 46.14.180**. DEC's regulatory authority to determine compliance with these statutes is found in **18 AAC 50.200** Information requests; and **18 AAC 0.201** Ambient air quality investigations. As stated previously, the State of Alaska adopted the 2010 1-hour SO_2 NAAQS into **18 AAC 50.010** on August 3, 2011; this regulation became effective on September 17, 2011. The State of Alaska adopted the 2010 1-hour NO_2 NAAQS on December 5, 2012; this regulation became effective on January 4, 2013. Monitoring protocols and test methods for stationary sources that have been adopted by reference into the State Air Quality Control Plan are found at **18 AAC 50.030**. The most current and federally approved reference (measurement) and interpretation methods for the 1-hour NO_2 and SO_2 NAAQS are adopted by reference in **18 AAC 50.035(b)(1)**.[15] Federal standards adopted by reference are found at **18 AAC 50.040**. Stationary source monitoring, reporting, and record keeping requirements are found in the standard permit conditions for construction and operating permits at **18 AAC 50.345**.

[15] 40 C.F.R. §50, Appendices A-1; F; and T.

	18 AAC 50.220 Enforceable test methods: DEC may require and owner or operator to conduct air pollutant emission tests to determine compliance with **AS 46.14** and associated regulations. **18 AAC 50.544 Minor Permits:** Provides for the installation, use and maintenance of monitoring equipment, sampling of emissions, source test, monitoring and emissions data reporting for minor sources.
§110(a)(2)(G) Authority to declare air pollution emergency and notify public **§110(a)(2)(G)** (continued)	DEC's statutory authority to act during air emergencies and air episodes is found under the following statutes: **AS 46.03.020 Powers of the departmen**t; **AS 46.03.810 Air and land nuisances**; **AS 46.03.820 Emergency powers**; and **AS 46.14.540 Authority of department in cases of emergency**. Alaska's regulations pertaining to air episodes and advisories are found at **18 AAC 50.245**. Alaska's 24-hour SO_2 concentrations triggering an air alert, warning and episode are found in **Table 6 at 18 AAC 50.245**. All regions in Alaska are classified as Priority III for NO_2 and SO_2 (see 40 CFR 52.71). As stated in 40 CFR 51.152(c), areas classified as Priority III regions are not required to develop emergency episode plans, which EPA has interpreted to mean the contingency plans otherwise required under 40 CFR 51.152. However, DEC can and does issue air advisories under **18 AAC 50.245** to address air episodes when air quality conditions warrant action. The three major municipalities in Alaska (MOA, FNSB, and CBJ) also have ordinances, codes, or regulations that enable them to declare emergencies in the case of poor air quality due to forest fires, volcanoes, wood smoke or other air quality problem. DEC personnel remain in close contact with each municipality when an air emergency is declared, assisting with air monitoring and analysis, and implementing safety and control measures, as needed.
§110(a)(2)(H) Future SIP Revisions	DEC's statutory authority to adopt regulations in order to implement the CAA and the state air quality control program is found in **AS 46.03.020(10) (A)**, and **AS 46.14.010(a)**. DEC's regulatory authority to implement any provision of the CAA is found in **18 AAC 50.005**. DEC strives to establish regulations and update Alaska's SIP in a timely fashion as new NAAQS are promulgated by EPA.
§110(a)(2)(J) §121 consultation	DEC's statutory authority to consult and cooperate with officials of local governments, state and federal agencies, and non-profit groups is found in **AS 46.030.020 (3)(8)**. Municipalities and local air quality districts seeking approval for a local air quality control program shall enter into a cooperative agreement with DEC according to **AS 46.14.400(d)**. DEC can adopt new CAA regulations only after a public hearing (**AS 46.14.010(a)**).

§110(a)(2)(J) **§127 public notification**	Public notice and public hearing regulations for SIP submittals and air quality discharge permits are found at **18 AAC 15.050** and **18 AAC 15.060**.
§110(a)(2)(J) **PSD & visibility protection**	DEC concludes that there are no new visibility protection obligations under CAA §110(a) (2) (J) as a result of the 2010 NO_2 and SO_2 NAAQS. Alaska's PSD/NSR program was originally approved by EPA on February 16, 1995 [60 FR 8943]. Amendments to DEC's PSD/NSR Program were most recently approved by EPA on August 14, 2007 [72 FR 45378] and February 9, 2011 [76 FR 7116]. See section 110(a) (2) (C) above.
§110(a)(2)(K) **Air quality modeling/data** **§110(a)(2)(K)** (continued)	DEC conducts air quality modeling under **18 AAC 50.215(b)**, ambient air quality analysis methods. Estimates of ambient concentrations and visibility impairment are based on applicable air quality models, databases, and other requirements specified in the EPA's Guideline on Air Quality Models adopted by reference in **18 AAC 50.040(f)**. EPA's monitoring guidance entitled "*Ambient Monitoring Guidelines for the Prevention of Significant Deterioration*" is adopted by reference at **18 AAC 50.035(5)**. As mentioned previously, EPA's "*Guideline on Air Quality Models*" (Appendix W to 40 CFR Part 51) is adopted by reference in **18 AAC 50.040(f)**. This regulation allows some provisions to exclude concentrations attributable to temporary construction activity for a new or modified source, or to new sources outside the United States. The most recent revision to Appendix W was published on November 9, 2005 [70 FR 68228], wherein EPA adopted AERMOD as the preferred dispersion model. Appendix W, and therefore AERMOD, is also adopted by reference at **18 AAC 50.215(b)(1)** and is used by DEC during its ambient air quality analysis for the prevention of significant deterioration. Ambient air quality and meteorological data that are collected for PSD purposes by permitted stationary sources are reported to DEC on a quarterly and annual basis.
§110(a)(2)(L) **Major Stationary source permitting fees**	DEC's statutory authority to assess and collect permit fees is established in **AS 46.14.240** and **AS 46.14.250**. The permit fees for major and minor stationary sources are assessed and collected by the Air Permits Program according to **18 AAC Article 4. User Fees** (18 AAC 50.400 through 18 AAC 50.430). Permit administration fees and permit emission fees are calculated according to DEC's regulations found in **18 AAC 50.400** and **18 AAC 50.410**, respectively. Billing procedures for emission fees are administered according to **18 AAC 50.420**. The Air Permits Program is required to evaluate emission fee rates at least every four years, and provide a written evaluation of the findings (**AS 46.14.250(g)**; **18 AAC 50.410**). The Division's most recent emission fee

	evaluation report was completed in October 2010. The Division's next emission fee review is scheduled for 2014.
§110(a)(2)(M) Consultation/Participation by affected local entities	**AS 46.03.020(3)(A)(B)** provides DEC the statutory authority to consult and cooperate with officials and representatives of any organization in the state; and persons, organization, and groups, public and private using, served by, interested in, or concerned with the environment of the state. **AS 46.03.020(8)** provides DEC the authority to "advise and cooperate with municipal, regional, and other local agencies and officials in the state, to carry out the purposes of this chapter." **AS 46.14.400(d)** provides authority for local air quality control programs and requires cooperative agreements between DEC and local air quality control programs that specify the respective duties, funding, enforcement responsibilities and procedures.

Attachments

The following attachments are intended to demonstrate Alaska's compliance with CAA §110 §110(a)(2)(E)(ii) and the intent of CAA §128 "conflict of interest" phrases. DEC has submitted these existing regulations to meet the intent of CAA §110 (a) (2) (E) and CAA §128 for this CAA §110 certification and for all future CAA §110 certification amendments to the SIP.

Attachment 1- Alaska Administrative Code Title 2- Administration, Chapter 50. Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulation of Lobbying**-** Article 1. Public Official Financial Disclosure.

Attachment 2- Alaska Administrative Code Title 9- Law, Chapter 52. Executive Branch Code of Ethics.

ATTACHMENT #1

ALASKA ADMINISTRATIVE CODE

TITLE 2- ADMINISTRATION

Chapter 50. Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulation of Lobbying

Article 1. Public Official Financial Disclosure

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Chapter 50. Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulation of Lobbying.

Article

Editor's note: As of Register 78, the Alaska Public Offices Commission regulations which were formerly located in 6 AAC 29 are now located in 2 AAC 50, in light of Executive Order No. 41 (1980). The history notes under the sections in their new location carry forward the history of those provisions from their old location.

Article 1. Public Official Financial Disclosure.

Section

2 AAC 50.010. Reporting sources of income from retail businesses. For the purposes of reporting a source of income under

AS 39.50.030(b), a filer shall report the name

(1) and address of a source of income that is a retail business; and

(2) of a customer of a retail business that is a source of income, if the customer

(A) conducted business with the retail business through a line of credit that extended through two or more billing cycles;

(B) had an ongoing contract to purchase goods or services from the retail business; or

(C) paid the retail business more than $1000 for a good or service after receiving a discount that was not available to the general public. (Eff. 8/20/75, Register 55; am 5/16/76, Register 58; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.015. Reporting sources of income from political campaigns and gifts for office expenses. Repealed. (Eff. 1/26/86, Register 97; am 7/20/95, Register 135; repealed 1/1/2001, Register 156)

2 AAC 50.020. Reporting interests in real property. For the purposes of reporting the identity and nature of an interest in real property under AS 39.50.030(b), a filer shall report a description of the nature of the interest held in the property and the address or other legal description of the property. (Eff. 5/16/76, Register 58; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.025. Reporting sources of income from rental property. For the purposes of reporting a source of income under AS 39.50.030(b) from rental property located

(1) within the state, a filer shall report the name of a person that paid more than $1000 in rent during the preceding calendar year; and

(2) outside the state and managed by a

(A) filer or the filer's family member, the filer shall report the name of a person that paid more than $1000 in rent during the preceding calendar year; or

(B) person other than a filer or the filer's family member, the filer shall report the name of the manager. (Eff. 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.030. Duty to report family member financial affairs. For the purposes of reporting information on the financial affairs of a filer's family member, the filer shall

(1) make an affirmative good faith effort to ascertain the information; and

(2) report the information that the filer knows. (Eff. 5/16/76, Register 58; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.035. Duty to report concluded business interests. For the purposes of reporting information under AS 39.50.030(b) on a business ownership interest that is no longer held but was held during the preceding calendar year by a filer or the filer's family member, the filer shall

(1) make an affirmative good faith effort to ascertain the information; and

(2) report the information that the filer knows. (Eff. 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.040. Loans, loan guarantees, and indebtedness. (a) For the purposes of reporting a creditor under AS 39.50.030(b), a filer need not report a retail charge account creditor, revolving charge account creditor, or credit card creditor.

(b) As used in AS 39.50.030(b) and this section, "loan or loan guarantee" includes a business or personal

(1) loan signed or cosigned by a filer or the filer's family member; and

(2) loan guarantee made on behalf of a filer or the filer's family member. (Eff. 5/16/76, Register 58; am 5/14/80, Register 74; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.050. Retail charge accounts. Repealed. (Eff. 5/16/76, Register 58; repealed 7/20/95, Register 135)

Editor's note: As of Register 135, October 1995, the substance of former 2 AAC 50.050 is included in 2 AAC 50.040.

2 AAC 50.060. Write-in candidates. A public statement by an individual not appearing on the ballot that he will seek elective office constitutes a declaration of candidacy under AS 39.50.020. (Eff. 5/16/76, Register 58; am 5/14/80, Register 74)

Authority: AS 15.13.030(10) AS 39.50.020

2 AAC 50.070. Income. As used in AS 39.50 and 2 AAC 50.010 — 2 AAC 50.200, "income" includes money or anything of value received

(1) in exchange for labor or services;
(2) from the sale of goods or property;
(3) as profit from a financial investment;
(4) as alimony;
(5) as child support;
(6) as a government entitlement;
(7) as an honorarium; or
(8) as a gift. (Eff. 5/16/76, Register 58; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.075. Reporting sources of income from gifts. For the purposes of reporting a source of income under AS 39.50.030(b), a filer shall report the name of the donor of a gift or a series of gifts if the

(1) value of the gift or the cumulative value of the series of gifts from the donor is over $250;
(2) gift or series of gifts is received by the filer or the filer's family member; and
(3) donor is not related to the recipient as a spouse, spousal equivalent, parent, child, sibling, grandparent, aunt, uncle, niece, or nephew. (Eff. 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.080. Controlling interest in a corporation. As used in AS 39.50 and 2 AAC 50.010 — 2 AAC 50.200, "controlling interest" in a corporation means ownership of more than 50 percent interest or more than 50 percent of the outstanding shares at any time during the preceding calendar year. (Eff. 5/16/76, Register 58; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.050 AS 39.50.200

2 AAC 50.090. Municipalities as instrumentalities of the state. In AS 39.50.200(5), "instrumentality of the state" includes municipalities. (Eff. 5/16/76, Register 58)

Authority: AS 15.13.030(10) AS 39.50.200(5)

2 AAC 50.095. Reporting sources of income from self-employment. For the purposes of reporting a source of income under AS 39.50.030(b) from self-employment, a filer shall list the name of a non-retail customer, client, or patient of a

(1) sole proprietorship, partnership, or professional corporation in which the filer or the filer's family member is an owner, partner, or shareholder; or

(2) corporation in which the filer, the filer's family member, or a combination of these individuals owns a controlling interest. (Eff. 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.050 AS 39.50.200
AS 39.50.030

2 AAC 50.100. Exemption from reporting name of individual as a source of income. (a) A filer who seeks an exemption from the requirement to report the name of a source of income under AS 39.50.030(b) or 2 AAC 50.010 — 2 AAC 50.200 shall request the exemption from the commission.

(b) To request an exemption under (a) of this section, a filer shall file a written request for exemption with the statement for which the exemption is requested. The written request for exemption must be on a form prescribed by the commission and must, for a name for which an exemption is requested,

(1) state the facts that support the exemption; and

(2) identify the exemption circumstances under (c) — (j) of this section that applies to the request.

(c) A filer may request a mental health practice exemption if during the preceding calendar year the

(1) filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation in which a mental health practitioner, including a psychiatrist, psychologist, or therapist, worked;

(2) source of income was an individual who received mental health services from the mental health practitioner; and

(3) income was received as payment for the mental health services.

(d) A filer may request a sensitive medical practice exemption if during the preceding calendar year

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(2) at least 67 percent of the patients of the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation consisted of individuals who

(A) received medical services related to abortion, contraception, reproductive health, a sexual disorder, or a terminal illness from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(B) were minors, and who, unknown to their parents or legal guardians, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; or

(C) were married, and who, unknown to their spouses, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(3) the source of income was an individual who received medical services of any nature from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; and

(4) the income was received as payment for the medical services.

(e) A filer may request a sensitive medical procedure exemption if during the preceding calendar year the

(1) filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(2) source of income was an individual who received medical services related to abortion, contraception, reproductive health, a sexual disorder, or a terminal illness from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; and

(3) income was received as payment for the medical services.

(f) A filer may request an embarrassing medical procedure exemption if during the preceding calendar year

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(2) the source of income was a

(A) minor who, unknown to a parent or legal guardian of the minor, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; or

(B) married individual who, unknown to the individual's spouse, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(3) the income was received as payment for the medical services; and

(4) reporting the name of the source of income would tend to cause a reasonable person in the situation of the source of income substantial concern, anxiety, or embarrassment.

(g) A filer may request a legal services practice exemption if during the preceding calendar year

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability

partnership, professional corporation, or corporation where an attorney worked;

(2) at least 67 percent or more of the clients of the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation consisted of individuals who were

(A) minors, and who, unknown to their parents or legal guardians, received professional legal services from the attorney; or

(B) married, and who, unknown to their spouses, received professional legal services from the attorney;

(3) the source of income was an individual who received legal services of any nature from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; and

(4) the income was received as payment for the professional legal services.

(h) A filer may request a legal services exemption if

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation where an attorney worked;

(2) the source of income was a

(A) minor who, unknown to a parent or legal guardian of the minor, received professional legal services from the attorney; or

(B) married individual who, unknown to the individual's spouse, received professional legal services from the attorney;

(3) the income was received as payment for the professional legal services; and

(4) reporting the name of the source of income would tend to cause a reasonable person in the situation of the source of income substantial concern, anxiety, or embarrassment.

(i) A filer may request a filer prohibition exemption if the filer is prohibited by law from reporting the name of a source of income.

(j) A filer may request a right of source exemption if the filer believes that reporting the name of a source of income would violate a right of the source under the state or federal constitution. (Eff. 9/9/78, Register 67; am 5/14/80, Register 74; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030, AS 39.50.030, AS 39.50.035, AS 39.50.050

2 AAC 50.102. Commission consideration of exemption requests. (a) For an exemption circumstance under 2 AAC 50.100(c), (d), (e), (g), or (i), and no later than 30 days after the commission receives a written exemption request that complies with 2 AAC 50.100(b), the staff of the commission shall

(1) grant the request, if the facts stated in the request satisfy the exemption circumstance upon which the request relies; and

(2) send to the filer, at the address on file with the commission, a written notice of the staff's decision to grant or deny the exemption.

(b) If under (a) of this section the staff of the commission grants a request, the filer need not report the name of the source of the income for which the request is made. If the staff denies the request, the filer shall, no later than 30 days after the date of the staff's written notice under (a) of this section,

(1) report the name of the source of income as required under AS 39.50.030; or

(2) file with the commission a notice of appeal, which

(A) must contain the information described in 2 AAC 50.100(h);

(B) must explain why the filer believes that the staff erred in denying the filer's request for exemption; and

(C) may include additional information that the filer considers appropriate.

(c) If the filer does not file a timely written notice of appeal under (b) of this section, the decision by the staff of the commission is final, and may not be appealed to the commission.

(d) If the filer files a timely notice of appeal under (b) of this section, the commission will hear the appeal at the next scheduled meeting of the commission, unless the commission, in its discretion, finds good cause to hear the appeal at a different meeting. At the hearing, an attorney may represent the filer. Unless the commission provides otherwise, the filer shall present the filer's case first, and the staff of the commission shall present its case next. After the hearing, the commission will grant or deny the request for an exemption.

(e) For an exemption circumstance under 2 AAC 50.100(f), (h), or (j), and no later than 30 days after the commission receives a written exemption request that complies with 2 AAC 50.100(b), the staff of the commission shall

(1) determine whether the facts stated in the request satisfy the requirements of the exemption circumstance upon which the request relies;

(2) make a preliminary finding, which recommends that the commission grant or deny the request;

(3) send to the filer, at the address on file with the commission, a written notice of the preliminary finding; and

(4) submit the preliminary finding to the commission for action under (f) of this section.

(f) After the staff of the commission has submitted a preliminary finding made under (e) of this section, the commission will

(1) review the preliminary finding at the next scheduled meeting of the commission, unless the commission, in its discretion, finds good cause to review the finding at a different meeting; and

(2) accept, reject, or modify the preliminary finding.

(g) No later than 30 days after reviewing a notice of appeal under (d) of this section or a preliminary finding under (f) of this section, the commission will send to the filer, at the address on file with the commission, written notice of the commission's final decision and an order granting or denying the request for exemption.

(h) If under (g) of this section the commission

(1) grants a request for exemption, the filer need not report the name of the source of income; and

(2) denies a request for exemption, the filer shall

(A) report the name of the source of income as required under AS 39.50.030 no later than 30 days after the date of the commission's order; or

(B) file a notice of appeal under AS 44.62.560.

(i) If while considering a request for exemption the commission or the staff of the commission determines that information that the commission or the staff has received is protected by a state or federal constitutional right or is legally privileged, the commission and the staff will keep the information confidential, without regard to whether the filer claims the right or privilege.

(j) A filer does not violate AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200 for failure to report the name of a source of income if the filer has requested an exemption under 2 AAC 50.100 and

(1) the commission has not issued a written final decision and order regarding a preliminary finding that the staff of the commission has submitted under (e) of this section; or

(2) a notice of appeal that the filer has submitted under (b) or (h) of this section is under review. (Eff. 7/20/95, Register 135)

Authority: AS 15.13.030 AS 39.50.035 AS 39.50.050
AS 39.50.030

2 AAC 50.105. Filing. (a) The public officials named in AS 39.50.200(a) who are required to file a statement under AS 39.50.020 shall file the statement with an office of the commission by hand delivery, mail, or facsimile.

(b) A candidate for state elective office who is required to file a statement with the director of elections under AS 39.50.020 shall file the statement as the director of elections provides.

(c) A municipal officer or a candidate for elective municipal office who is required to file a statement with the municipal clerk or another municipal official under AS 39.50.020 shall file the statement as the clerk or municipal official provides.

(d) If an individual who is subject to (a) of this section files a statement by hand delivery or facsimile, the date of filing is the date on which an office of the commission receives the statement. If the individual files a statement by mail, the date of filing is the date of the postmark. If a statement filed by mail has a postmark on which the date is missing or illegible, the date of the postmark is rebuttably presumed to be 10 calendar days before the date on which the statement is received.

(e) If a filer is required to file more than one statement under AS 39.50.020, the filer shall file a statement at each place designated in AS 39.50.020. A filer may file a copy of a current statement. The filer shall sign the copy. (Eff. 9/9/78, Register 67; am 5/14/80, Register 74; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.020 AS 39.50.050

2 AAC 50.107. Taking office. As used in AS 39.50.020(a), "within 30 days after taking office" means within 30 days after the earlier of the following days:

(1) the day on which the filer first earns compensation for work;

(2) the day on which the filer takes the oath of office. (Eff. 7/20/95, Register 135)

Authority: AS 15.13.030 AS 39.50.020 AS 39.50.050

2 AAC 50.108. Notice of filing requirement. (a) If the staff of the commission determines that an executive branch public official or a judicial officer must file a statement under AS 39.50.020, the staff shall send a written notice to the individual at the address on file with the commission.

(b) The staff of the commission shall provide each municipality a copy of the statement form and instruction manual for each municipal officer and candidate subject to AS 39.50. (Eff. 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.020 AS 39.50.050

2 AAC 50.110. Civil penalty for late or incomplete statements from filers other than municipal officers. (a) Except as provided under 2 AAC 50.143, the staff of the commission shall assess a civil penalty under AS 39.50.135 against a filer other than a municipal officer on each day that the filer's statement is late. A statement is late or incomplete if it is not complete and filed

(1) 30 days after the commission sends notice under 2 AAC 50.108, for an initial statement from an executive branch public official or judicial officer; and

(2) March 15, for an annual statement.

(b) For a statement required because a filer is an executive branch public official, candidate for state elective office, or judicial officer, the staff of the commission shall assess the civil penalty against the filer as follows:

(1) $5 per late day through the first 15 days of lateness;

(2) $10 per late day for the 16th and subsequent days of lateness.

(c) Notwithstanding (b) of this section, the staff of the commission may recommend that the commission assess $10 per day for each day that a statement is late if a filer other than a municipal officer has

(1) failed to comply substantially with AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200 by failing to report in the filer's statement a major source of income, interest in real property, business interest, loan, trust, or other substantial financial interest; or

(2) continuously failed to comply with AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200 by failing to respond fully and within the time prescribed to a written request from the commission or the staff for further information.

(d) A civil penalty assessed under (b) or (c) of this section is due each day that it is assessed. (Eff. 9/9/78, Register 67; am 5/14/80, Register 74; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030, AS 39.50.020, AS 39.50.050, AS 39.50.135

2 AAC 50.112. Dispute as to amount of civil penalty. (a) If a filer disputes the amount of a civil penalty assessed under 2 AAC 50.110(b) or 2 AAC 50.135(e), the filer may submit to the commission an affidavit stating facts in mitigation within 30 days of the date of the notice described in 2 AAC 50.115(e), 2 AAC 50.120(e), or 2 AAC 50.135(e). At its next meeting after the filer submits the affidavit, the commission will consider the affidavit and other evidence relevant to the amount of the civil penalty, unless the commission, in its discretion, finds reason to consider the affidavit at a different meeting. The commission will permit the filer to speak at the meeting. After considering the affidavit and other evidence, the commission will

(1) affirm the civil penalty if the commission determines that the statement was late without good cause; or

(2) reduce or waive the civil penalty if the commission determines that the statement was late for good cause.

(b) No later than 60 days after a meeting described in (a) of this section, the staff of the commission shall send a written notice of the decision by the commission to the filer at the address on file with the commission.

(c) If the commission decides to impose some or all of a civil penalty assessed under 2 AAC 50.110(b) or 2 AAC 50.135(e), the filer shall

(1) pay the penalty no later than 30 days after the date of the notice described in (b) of this section; or

(2) file a notice of appeal under AS 39.50.135 or AS 44.62.560. (Eff. 7/20/95, Register 135)

Authority: AS 15.13.030 AS 39.50.050 AS 39.50.135
AS 39.50.020

2 AAC 50.115. Procedures for late atatementa from executive branch public officials. (a) If the annual statement of an executive branch public official is late for eight days, the staff of the commission shall send a written notice to the executive branch public official at the address on file with the commission. The notice must state

(1) that the statement has not been filed;

(2) the date on which the statement was due;

(3) that refusal or failure to file

(A) is punishable as a misdemeanor offense; and

(B) on or before the 30th day of lateness will cause the commission to

(i) request the governor to remove the executive branch public official from office under AS 39.50.060 — 39.50.080, if the executive branch public official is not the governor or the lieutenant governor;

(ii) request the state agency that administers the salary, per diem, and travel expenses of the executive branch public official to withhold those payments under AS 39.50.070, 39.50.080, or 39.50.130;

(iii) request the attorney general to initiate misdemeanor proceedings under AS 39.50.060 — 39.50.080 or 39.50.130; and

(iv) take other action as appropriate to carry out AS 39.50.060 — 39.50.080 or 39.50.130;

(4) the amount of the civil penalty assessed to date under 2 AAC 50.110;

(5) that the civil penalty assesaed under 2 AAC 50.110 increases until the statement is filed; and

(6) the right of appeal under AS 39.50.135 and 2 AAC 50.112.

(b) If the annual statement of an executive branch public official is late for 22 days, the staff of the commission shall send a written notice to the executive branch public official at the address on file with the commission. The notice must include the information included in a notice sent under (a) of this section.

(c) If the annual statement of an executive branch public official has been late for 30 days, the staff of the commission shall

(1) send a written notice to the executive branch public official at the address on file with the commission; the notice must include the information included in a notice sent under (a) of this section;

(2) notify the commission that the statement has been late for 30 daya; and

(3) under the direction of the commission, take other action as appropriate to carry out AS 39.50.060 — 39.50.080 and 39.50.130.

(d) If the annual statement of an executive branch public official is late for 30 days, the commission will

(1) request the governor to remove the official from office under AS 39.50.060 — 39.50.080, unless the official is the governor or lieutenant governor;

(2) request the state agency that administers the salary, per diem, and travel expenses of thc executive branch public official to withhold those payments under AS 39.50.070, 39.50.080, or 39.50.130;

(3) request the attorney general to initiate misdemeanor proceedings under AS 39.50.060 — 39.50.080 or 39.50.130; and

(4) take other action as appropriate to carry out AS 39.50.060 — 39.50.080 or 39.50.130.

(c) If an executive branch public official files a statement after the date applicable to that official under AS 39.50.020(a), the staff of the commission shall send a written notice to the executive branch public official at the address on file with the commission. The notice must state the

(1) amount of the civil penalty assessed under 2 AAC 50.110; and

(2) right of appeal under AS 39.50.135 and 2 AAC 50.112. (Eff. 9/9/78, Register 67; am 10/18/81, Register 80; am 1/26/86, Register 97; am 7/20/95, Register 135)

Authority:	AS 15.13.030	AS 39.50.060	AS 39.50.080
	AS 39.50.020	AS 39.50.070	AS 39.50.130
	AS 39.50.050		

2 AAC 50.120. Procedures for late statements from judicial officers. (a) If the annual statement of a judicial officer is late for eight days, the staff of the commission shall send a written notice to the judicial officer at the address on file with the commission. The notice must state

(1) that the statement has not been filed;

(2) the date on which the statement was due;

(3) that refusal or failure to file

(A) is punishable as a misdemeanor offense; and

(B) on or before the 30th day of lateness will cause the commission to

(i) request the administrator of the court system to withhold salary, per diem, and travel expense payments to the judicial officer under AS 39.50.110;

(ii) request the Commission on Judicial Conduct to refer the matter to the supreme court with a recommendation that the judicial officer be removed from office under AS 39.50.110;

(iii) request the attorney general to initiate misdemeanor proceedings under AS 39.50.060 or 39.50.110; and

(iv) take other action as appropriate to carry out AS 39.50.060 or 39.50.110;

(4) the amount of the civil penalty assessed to date under 2 AAC 50.110;

(5) that the civil penalty assessed under 2 AAC 50.110 increases until the statement is filed; and

(6) the right of appeal under AS 39.50.135 and 2 AAC 50.112.

(b) If the annual statement of a judicial officer is late for 22 days, the staff of the commission shall send a written notice to the judicial officer at the address on file with the commission. The notice must include the information included in a notice sent under (a) of this section.

(c) If the annual statement of a judicial officer is late for 30 days, the staff of the commission shall

(1) send a written notice to the judicial officer at the address on file with the commission; the notice must include the information included in a notice sent under (a) of this section;

(2) notify the commission that the statement has been late for 30 days; and

(3) under the direction of the commission, take other action as appropriate to carry out AS 39.50.060 and 39.50.110.

(d) If the annual statement of a judicial officer is late for 30 days, the commission will

(1) request the administrator of the court system to withhold salary, per diem, and travel expense payments to the judicial officer under AS 39.50.110;

(2) request the Commission on Judicial Conduct to refer the matter to the supreme court with a recommendation that the judicial officer be removed from office under AS 39.50.110;

(3) request the attorney general to initiate misdemeanor proceedings under AS 39.50.060 or 39.50.110; and

(4) take other action as appropriate to carry out AS 39.50.060 or 39.50.110.

(e) If a judicial officer files a statement after the date applicable to that officer under AS 39.50.020(a), the staff of the commission shall send a written notice to the judicial officer at the address on file with the commission. The notice must state the

(1) amount of the civil penalty assessed under 2 AAC 50.110; and

(2) right of appeal under AS 39.50.135 and 2 AAC 50.112. (Eff. 9/9/78, Register 67; am 10/18/81, Register 80; am 1/26/86, Register 97; am 7/20/95, Register 135)

Authority:	AS 15.13.030	AS 39.50.050	AS 39.50.110
	AS 39.50.020	AS 39.50.060	

2 AAC 50.125. Procedures followed upon a refusal or failure by a state elected official to file the conflict-of-interest statement when due. Repealed 10/18/81.

2 AAC 50.126. Procedures for failure or refusal of an incumbent state elected official to file the annual conflict-of-interest statement by the April 15 due date. Repealed. (Eff. 10/18/81, Register 80; repealed 7/20/95, Register 135)

2 AAC 50.127. Procedures for incomplete statements from candidates for state elective office. (a) Seven days before the primary election withdrawal date set in AS 15.25.055 and seven days before the general election withdrawal date set in AS 15.25.200, the staff of the commission shall provide to the commission a list of the candidates for state elective office whose statements are incomplete.

(b) Upon receipt of a list described in (a) of this section, the commission will schedule a meeting to consider the list. The staff of the commission shall notify a candidate for state elective office who is on the list about the time, date, and place of the meeting.

(c) If, at or after the meeting scheduled under (b) of this section, the commission determines that a candidate for state elective office has not supplied required information on a major source of income, interest in real property, business interest, loan, or trust, the commission will recommend that the lieutenant governor remove the candidate's name from the ballot. If the candidate's name cannot be removed from the ballot, the commission will recommend that the lieutenant governor not certify the candidate's nomination for office or election to office.

(d) If information discovered after the withdrawal-of-candidacy deadline indicates that a candidate for state elective office has failed to comply substantially with the requirements of AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200, the staff of the commission shall undertake a preliminary investigation under 2 AAC 50.460. The staff shall report its findings to the commission. The commission will determine the appropriate penalty. (Eff. 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority:	AS 15.13.030	AS 39.50.060	AS 39.50.130
	AS 39.50.020	AS 39.50.120	AS 39.50.135
	AS 39.50.050		

2 AAC 50.130. Filing by a municipal officer. Repealed. (Eff. 9/9/78, Register 67; am 5/14/80, Register 74; repealed 7/20/95, Register 135)

2 AAC 50.135. Civil penalty assessments for late filing by municipal officers. (a) The statement of a municipal officer is delinquent if the municipal clerk or designated municipal official does not receive the statement on or before March 15, for an annual statement.

(b) The statement continues to be delinquent and subject to a civil penalty until received by the municipal clerk or designated official.

(c) The municipal clerk or designated official shall notify the commission within five days

(1) by telegram or telephone of the name and address of any municipal officer who has refused or failed to file a statement by the due date; and

(2) verify that all other municipal officers have filed.

(d) Within five days after receiving a notification under (c) of this section, the staff of the commission shall send a written notice to the municipal officer. The notice must state

(1) that the statement has not been filed;

(2) the date on which the statement was due;

(3) that refusal or failure to file

(A) is punishable as a misdemeanor offense; and

(B) on or before the 30th day of lateness will cause the commission to

(i) request the attorney general to initiate misdemeanor proceedings under AS 39.50.060; and

(ii) take other action as appropriate to carry out AS 39.50.060;

(4) the amount of the civil penalty assessable to date under (e) of this section;

(5) that the civil penalty assessable under (e) of this section increases until the statement is filed; and

(6) the right of appeal under AS 39.50.135 and 2 AAC 50.112.

(e) The municipal clerk or designated official shall notify the commission by telegram or telephone of the name and address of any municipal officer who filed a delinquent statement and the date on which the late statement was received by the clerk or designated official. Upon notification of the receipt of a delinquent statement, commission staff shall

(1) assess a civil penalty of

(A) $1 a day for the first seven days a statement is delinquent; and

(B) $5 a day for the eighth day and subsequent days of delinquency; and

(2) within five days after notification by the municipal clerk or designated official of receipt of a delinquent statement, send a notice of the civil penalty assessed against the municipal officer and a form for appealing the assessment.

(f) If a municipal officer disputes the amount of a civil penalty assessed under (e) of this section, the municipal officer, using the affidavit appeal form provided under (e) of thia section, may submit to the commission an affidavit stating facts in mitigation within 30 days of the date of the notice described in (e) of this section. The commission will review the affidavit under the procedures set out at 2 AAC 50.112.

(g) Repealed 7/20/95.

(h) Repealed 7/20/95.

(i) Repealed 7/20/95.

(j) Notwithstanding (e) of this section, the staff of the commission may recommend that the commission assess $10 per day for each day that a statement is late if a municipal officer has

(1) failed to comply substantially with AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200 by failing to report in the officer's statement a major source of income, interest in real property, business interest, loan, trust, or other substantial financial interest; or

(2) continuously failed to comply with AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200 by failing to respond fully and within the time prescribed to a written request from the commission or staff for further information. (Eff. 9/9/78, Register 67; am 5/14/80, Register 74; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030, AS 39.50.020, AS 39.50.050, AS 39.50.135

2 AAC 50.140. Procedures for incomplete statements from candidates for elective municipal office. (a) Seven days before the deadline for withdrawal of candidacy, the staff of the commission shall provide the commission a list of the candidates for elective municipal office whose statements are incomplete.

(b) Upon receipt of the list described in (a) of this section, the commission will schedule a meeting to consider the list. The staff of the commission shall notify a candidate for elective municipal office who is on the list about the time, date, and place of the meeting.

(c) If, at or after a meeting scheduled under (b) of this section, the commission determines that a candidate for elective municipal office has not supplied required information on a major source of income, interest in real property, business interest, loan, or trust, the commission will recommend that the appropriate municipal clerk or designated municipal official refuse or return the candidate's filing fees and filing for office and remove the candidate's name from the filing records.

(d) If information discovered after the withdrawal-of-candidacy deadline indicates that a candidate for elective municipal office has failed to comply substantially with the requirements of AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200, the staff of the commission shall undertake a preliminary investigation under 2 AAC 50.460. The staff shall report its findings to the commission. The commission will determine the appropriate penalty. (Eff. 9/9/78, Register 67; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030, AS 39.50.020, AS 39.50.050, AS 39.50.060

2 AAC 50.143. Corrected incomplete statements. If the staff of the commission discovers an obvious deficiency on the face of a statement, the staff shall notify the filer of the deficiency. If the filer corrects the deficiency by filing a statement that contains the required information no later than 15 days after the date of the staff's notice, the staff

(1) shall consider the correction to be a fact in mitigation as described in AS 39.50.135; and

(2) may not assess a civil penalty under 2 AAC 50.110 or 2 AAC 50.135. (Eff. 7/20/95, Register 135)

Authority: AS 15.13.030 AS 39.50.050 AS 39.50.135
AS 39.50.030

2 AAC 50.145. Substantial or continuing noncompliance. Repealed. (Eff. 1/26/86, Register 97; repealed 7/20/95, Register 135)

Editor's note: As of Register 135, October 1995, the substance of former 2 AAC 50.145 is located at 2 AAC 50.110(c) and 2 AAC 50.135(j).

2 AAC 50.200. Definitions. As used in AS 39.50 and 2 AAC 50.010 — 2 AAC 50.200, unless the context requires otherwise,

(1) "candidate" means a candidate for

(A) state elective office; and

(B) elective municipal office;

(2) "child" has the meaning given in AS 39.50.200(a);

(3) "commission" means the Alaska Public Offices Commission created under AS 15.13.020(a);

(4) "executive branch public official" means a public official within the definition given in AS 39.50.200(a), except for a judicial officer or a municipal officer;

(5) "filer" means a public official as defined in AS 39.50.200(a);

(6) "gift"

(A) means a payment or item to the extent that consideration of equal or greater value is not received;

(B) includes

(i) forgiveness of a loan, payment of a loan by a third party, or an enforceable promise to make a payment except when full and adequate consideration is received;

(ii) the provision of accommodations;

(iii) the provision of a ticket for travel or for an entertainment event;

(iv) the provision of food or beverages other than food or beverages for immediate consumption;

(v) the granting of a discount or rebate not extended to the public generally for a good or service; and

(vi) the provision or loan of goods or services for personal or professional use, including office expenses connected with holding public office, unless made in exchange for consideration of equal or greater value; and

(C) does not include

(i) a political contribution;

(ii) a commercially reasonable loan made in the ordinary course of business in exchange for consideration of equal or greater value; or

(iii) an inheritance;

(7) "judicial officer" has the meaning given in AS 39.50.200(a), but does not include a judicial officer who holds a judicial office for less than 30 days;

(8) "municipal officer" has the meaning given in AS 39.50.200(a);

(9) "source of income" has the meaning given in AS 39.50.200(a);

(10) "spousal equivalent" has the meaning given in AS 39.50.200(a);

(11) "statement" means a statement or report of income sources and business interests required under AS 39.50;

(12) "family member" means a spouse, spousal equivalent, or dependent child, or the filer's nondependent child who lives with the filer;

(13) "public official" has the meaning given in AS 39.50.200(a). (Eff. 9/9/78, Register 67; am 7/20/95, Register 135; am 1/1/2001, Register 156)

Authority: AS 15.13.030 AS 39.50.050

ALASKA ADMINISTRATIVE CODE

Title 2

Administration

APRIL 2005 SUPPLEMENT
INCLUDING REGISTERS 164 THROUGH 173

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Chapter 50. Alaska Public Offices Commission: Conflict of Interest, Campaign Disclosure, Legislative Financial Disclosure, and Regulation of Lobbying.

Article 1. Public Official Financial Disclosure.

2 AAC 50.010. Reporting sources of income from retail businesses. For the purposes of reporting a source of income under AS 39.50.030(b), a filer shall report the name

(1) and address of a source of income that is a retail business; and

(2) of a customer of a retail business that is a source of income, if the customer

(A) conducted business with the retail business through a line of credit that extended through two or more billing cycles;

(B) had an ongoing contract to purchase goods or services from the retail business; or

(C) paid the retail business more than $5,000 for a good or service after receiving a discount that was not available to the general public. (Eff. 8/20/75, Register 55; am 5/16/76, Register 58; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156; am 2/20/2005, Register 173)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.025. Reporting sources of income from rental property. For the purposes of reporting a source of income under AS 39.50.030(b) from rental property located

(1) within the state, a filer shall report the name of a person that paid more than $5,000 in rent during the preceding calendar year; and

(2) outside the state and managed by a

(A) filer or the filer's family member, the filer shall report the name of a person that paid more than $5,000 in rent during the preceding calendar year; or

(B) person other than a filer or the filer's family member, the filer shall report the name of the manager. (Eff. 7/20/95, Register 135; am 1/1/2001, Register 156; am 2/20/2005, Register 173)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.075. Reporting sources of income from gifts. For the purposes of reporting a source of income under AS 39.50.030(b), a filer shall report the name of the donor of a gift or a series of gifts if the

(1) value of the gift or the cumulative value of the series of gifts from the donor is over $250;

(2) gift or series of gifts is received by the filer or the filer's family member; and

(3) donor is not related to the recipient as a spouse, domestic partner, parent, child, sibling, grandparent, aunt, uncle, niece, or nephew. (Eff. 7/20/95, Register 135; am 1/1/2001, Register 156; am 2/20/2005, Register 173)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.050

2 AAC 50.100. Exemption from reporting name of individual as a source of income. (a) A filer who seeks an exemption from the requirement to report the name of a source of income under AS 39.50.030(b) or 2 AAC 50.010 — 2 AAC 50.200 shall request the exemption from the commission.

(b) To request an exemption under (a) of this section, a filer shall file a written request for exemption with the statement for which the exemption is requested. The written request for exemption must be on a form prescribed by the commission and must, for a name for which an exemption is requested,

(1) state the facts that support the exemption; and

(2) identify the exemption circumstances under (c) — (j) of this section that applies to the request.

(c) A filer may request a mental health practice exemption if during the preceding calendar year the

(1) filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation in which a mental health practitioner, including a psychiatrist, psychologist, or therapist, worked;

(2) source of income was an individual who received mental health services from the mental health practitioner; and

(3) income was received as payment for the mental health services.

(d) A filer may request a sensitive medical practice exemption if during the preceding calendar year

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(2) at least 67 percent of the patients of the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation consisted of individuals who

(A) received medical services related to abortion, contraception, reproductive health, a sexual disorder, or a terminal illness from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(B) were minors, and who, unknown to their parents or legal guardians, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; or

(C) were married, and who, unknown to their spouses, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(3) the source of income was an individual who received medical services of any nature from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; and

(4) the income was received as payment for the medical services.

(e) A filer may request a sensitive medical procedure exemption if during the preceding calendar year the

(1) filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(2) source of income was an individual who received medical services related to abortion, contraception, reproductive health, a sexual disorder, or a terminal illness from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; and

(3) income was received as payment for the medical services.

(f) A filer may request an embarrassing medical procedure exemption if during the preceding calendar year

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(2) the source of income was a

(A) minor who, unknown to a parent or legal guardian of the minor, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; or

(B) married individual who, unknown to the individual's spouse, received medical services from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation;

(3) the income was received as payment for the medical services; and

(4) reporting the name of the source of income would tend to cause a reasonable person in the situation of the source of income substantial concern, anxiety, or embarrassment.

(g) A filer may request a legal services practice exemption if during the preceding calendar year

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation where an attorney worked;

(2) at least 67 percent or more of the clients of the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation consisted of individuals who were

(A) minors, and who, unknown to their parents or legal guardians, received professional legal services from the attorney; or

(B) married, and who, unknown to their spouses, received professional legal services from the attorney;

(3) the source of income was an individual who received legal services of any nature from the sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation; and

(4) the income was received as payment for the professional legal services.

(h) A filer may request a legal services exemption if

(1) the filer or the filer's family member was an owner, partner, or shareholder in a sole proprietorship, partnership, limited liability partnership, professional corporation, or corporation where an attorney worked;

(2) the source of income was a

(A) minor who, unknown to a parent or legal guardian of the minor, received professional legal services from the attorney; or

(B) married individual who, unknown to the individual's spouse, received professional legal services from the attorney;

(3) the income was received as payment for the professional legal services; and

(4) reporting the name of the source of income would tend to cause a reasonable person in the situation of the source of income substantial concern, anxiety, or embarrassment.

(i) A filer may request a filer prohibition exemption if the filer is prohibited by law from reporting the name of a source of income.

(j) A filer may request a right of source exemption if the filer believes that reporting the name of a source of income would violate a right of the source under the state or federal constitution.

(k) A filer may request a HIPAA exemption if the filer believes that reporting the name of a source of income would disclose protected health information that the filer is prohibited from disclosing under 42 U.S.C. 1320d - 1320d-8 (Health Insurance Portability and Accountability Act (HIPAA) of 1996). (Eff. 9/9/78, Register 67; am 5/14/80, Register 74; am 1/26/86, Register 97; am 7/20/95, Register 135; am 1/1/2001, Register 156; am 2/20/2005, Register 173)

Authority: AS 15.13.030 AS 39.50.030 AS 39.50.035 AS 39.50.050

2 AAC 50.102. Commission consideration of exemption requests. (a) For an exemption circumstance under 2 AAC 50.100(c), (d), (e), (g), (i), or (k), and no later than 30 days after the commission receives a written exemption request that complies with 2 AAC 50.100(b), the staff of the commission shall

(1) grant the request, if the facts stated in the request satisfy the exemption circumstance upon which the request relies; and

(2) send to the filer, at the address on file with the commission, a written notice of the staff's decision to grant or deny the exemption.

(b) If under (a) of this section the staff of the commission grants a request, the filer need not report the name of the source of the income for which the request is made. If the staff denies the request, the filer shall, no later than 30 days after the date of the staff's written notice under (a) of this section,

(1) report the name of the source of income as required under AS 39.50.030; or

(2) file with the commission a notice of appeal, which

(A) must contain the information described in 2 AAC 50.100(b);

(B) must explain why the filer believes that the staff erred in denying the filer's request for exemption; and

(C) may include additional information that the filer considers appropriate.

(c) If the filer does not file a timely written notice of appeal under (b) of this section, the decision by the staff of the commission is final, and may not be appealed to the commission.

(d) If the filer files a timely notice of appeal under (b) of this section, the commission will hear the appeal at the next scheduled meeting of the commission, unless the commission, in its discretion, finds good cause to hear the appeal at a different meeting. At the hearing, an attorney may represent the filer. Unless the commission provides otherwise, the filer shall present the filer's case first, and the staff of the commission shall present its case next. After the hearing, the commission will grant or deny the request for an exemption.

(e) For an exemption circumstance under 2 AAC 50.100(f), (h), or (j), and no later than 30 days after the commission receives a written exemption request that complies with 2 AAC 50.100(b), the staff of the commission shall

(1) determine whether the facts stated in the request satisfy the requirements of the exemption circumstance upon which the request relies;

(2) make a preliminary finding, which recommends that the commission grant or deny the request;

(3) send to the filer, at the address on file with the commission, a written notice of the preliminary finding; and

(4) submit the preliminary finding to the commission for action under (f) of this section.

(f) After the staff of the commission has submitted a preliminary finding made under (e) of this section, the commission will

(1) review the preliminary finding at the next scheduled meeting of the commission, unless the commission, in its discretion, finds good cause to review the finding at a different meeting; and

(2) accept, reject, or modify the preliminary finding.

(g) No later than 30 days after reviewing a notice of appeal under (d) of this section or a preliminary finding under (f) of this section, the commission will send to the filer, at the address on file with the commission, written notice of the commission's final decision and an order granting or denying the request for exemption.

(h) If under (g) of this section the commission

(1) grants a request for exemption, the filer need not report the name of the source of income; and

(2) denies a request for exemption, the filer shall

(A) report the name of the source of income as required under AS 39.50.030 no later than 30 days after the date of the commission's order; or

(B) file a notice of appeal under AS 44.62.560.

(i) If while considering a request for exemption the commission or the staff of the commission determines that information that the commission or the staff has received is protected by a state or federal constitutional right or is legally privileged, the commission and the staff will keep the information confidential, without regard to whether the filer claims the right or privilege.

(j) A filer does not violate AS 39.50 or 2 AAC 50.010 — 2 AAC 50.200 for failure to report the name of a source of income if the filer has requested an exemption under 2 AAC 50.100 and

(1) the commission has not issued a written final decision and order regarding a preliminary finding that the staff of the commission has submitted under (e) of this section; or

(2) a notice of appeal that the filer has submitted under (b) or (h) of this section is under review. (Eff. 7/20/95, Register 135; am 2/20/2005, Register 173)

Authority: AS 15.13.030 AS 39.50.035 AS 39.50.050
AS 39.50.030

2 AAC 50.200. Definitions. As used in AS 39.50 and 2 AAC 50.010 — 2 AAC 50.200, unless the context requires otherwise,

(1) "candidate" means a candidate for

(A) state elective office; and

(B) elective municipal office;

(2) "child" has the meaning given in AS 39.50.200(a);

(3) "commission" means the Alaska Public Offices Commission created under AS 15.13.020(a);

(4) "executive branch public official" means a public official within the definition given in AS 39.50.200(a), except for a judicial officer or a municipal officer;

(5) "filer" means a public official as defined in AS 39.50.200(a);

(6) "gift"

(A) means a payment or item to the extent that consideration of equal or greater value is not received;

(B) includes

(i) forgiveness of a loan, payment of a loan by a third party, or an enforceable promise to make a payment except when full and adequate consideration is received;

(ii) the provision of accommodations;

(iii) the provision of a ticket for travel or for an entertainment event;

(iv) the provision of food or beverages other than food or beverages for immediate consumption;

(v) the granting of a discount or rebate not extended to the public generally for a good or service; and

(vi) the provision or loan of goods or services for personal or professional use, including office expenses connected with holding public office, unless made in exchange for consideration of equal or greater value; and

(C) does not include

(i) a political contribution;

(ii) a commercially reasonable loan made in the ordinary course of business in exchange for consideration of equal or greater value; or

(iii) an inheritance;

(7) "judicial officer" has the meaning given in AS 39.50.200(a), but does not include a judicial officer who holds a judicial office for less than 30 days;

(8) "municipal officer" has the meaning given in AS 39.50.200(a);

(9) "source of income" has the meaning given in AS 39.50.200(a);

(10) repealed 2/20/2005;

(11) "statement" means a statement or report of income sources and business interests required under AS 39.50;

(12) "family member" means a spouse, domestic partner, or dependent child;

(13) "public official" has the meaning given in AS 39.50.200(a).

(14) "domestic partner" has the meaning given in AS 39.50.200(a). (Eff. 9/9/78, Register 67; am 7/20/95, Register 135; am 1/1/2001, Register 156; am 2/20/2005, Register 173)

Authority: AS 15.13.030 AS 39.50.050

ATTACHMENT #2

ALASKA ADMINISTRATIVE CODE

TITLE 9- LAW

Chapter 52. Executive Branch Code of Ethics

Register 131

October 1994

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CHAPTER 52. EXECUTIVE BRANCH CODE OF ETHICS.

9 AAC 52.010. APPEARANCE OF IMPROPRIETY. An appearance of impropriety does not establish that an ethical violation exists. (Eff. 4/25/94, Register 130)

Authority: AS 39.52.110 AS 39.52.950

9 AAC 52.020. IMPROPER MOTIVATION. A public officer may not take or withhold official action on a matter if the action is based on an improper motivation. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.110 AS 39.52.950

9 AAC 52.030. WHEN MEMBERSHIP IS SIGNIFICANT. (a) If a public officer is required by statute to be a member of a class and the public officer takes or withholds official action in a matter that affects all members of that class, the action is not a violation of the Ethics Act or this chapter unless the officer receives significant financial or personal benefit from the action or takes or withholds the action based on an improper motivation.

(b) A public officer's interest in a matter by reason of the officer's membership in a large organization or class is significant if the officer or an immediate family member of the officer has a significant personal or financial interest in the matter. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.110 AS 39.52.950

9 AAC 52.040. UNWARRANTED BENEFITS OR TREATMENT. (a) As used in AS 39.52.120(a), "unwarranted benefits or treatment" includes

(1) a deviation from normal procedures for the award of a benefit, regardless of whether the procedures were established formally or informally, if the deviation is based on the improper motivation; and

(2) an award of a benefit if the person receiving the benefit was substantially less qualified, in light of the formal or informal standards set out for the award, than another person who was or reasonably should have been considered for the award if the award is based on an improper motivation.

(b) A public officer may not grant or secure an unwarranted benefit or treatment, regardless of whether the result is in the best interest of the state.

(c) Subject to the requirements of AS 39.52.110, 39.52.120, 39.52.150, and AS 39.90.020, neither the Ethics Act nor this chapter prohibits a public officer from

(1) considering a person who has a relationship with an officer for a state contract or job if the person is considered on an equal basis with other applicants; or

(2) considering an individual's political affiliation or political support in determining whether to appoint the individual to a state board or commission or to hire the individual for an exempt or partially exempt state job. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.120 AS 39.52.950

9 AAC 52.050. USE OF STATE TIME, PROPERTY, EQUIPMENT, OR OTHER FACILITIES. A public officer who uses state time, property, equipment, or other facilities to benefit the officer's personal or financial interest is not in violation of AS 39.52.120(b)(3) if the officer's designated supervisor determines that the use is insignificant, the attorney general has not issued a general opinion against the use, and the attorney general does not advise the officer against the use. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.110 AS 39.52.120 AS 39.52.950

9 AAC 52.060. GIFTS. (a) As used in the Ethics Act and this chapter, a gift is a transfer or loan of property or provision of services to a public officer for less than full value. Unless rebutted by other evidence, and occasional gift worth $50 or less is presumed not to be given under circumstances in which it could be reasonably inferred that the gift is intended to influence an officer's performance of official duties, actions, or judgment.

(b) For purposes of AS 39.52.130, travel or lodging of any value received by a public officer in connection with a trip that the public officer takes as part of the officer's official duties is not an improper gift if the monetary value of the travel or lodging is comparable to the cost that the state would have had to pay for the travel or lodging and

(1) the head of the officer's agency determines that the gift is to the state, not to the officer; or

(2) the travel or lodging is incidental transportation by or hospitality at the residence of an individual. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.130 AS 39.52.950

9 AAC 52.070. INFORMATION DISSEMINATED TO THE PUBLIC. (a) For purposes of AS 39.140, information has been disseminated to the public if it has been published through newspaper publication; broadcast media; a press release; a newsletter; a legal notice; a non-confidential court filing; a published report; a public speech; or public testimony before the legislature, a board, or a commission.

(b) Information that is available to the public but that has not been published as described in (a) of this section has not been disseminated to the public. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.140 AS 39.52.950

9 AAC 52.080. STATE GRANTS, CONTRACTS, LEASES, AND LOANS. (a) For purposes of AS 39.52.150(b), a state grant, contract, or lease is competitively solicited if the grant, contract, or lease

(1) is awarded by competitive sealed bidding under AS 36.30.100 — 36.30.190 or competitive sealed proposals under AS 36.30.200 — 36.30.270; or

(2) is awarded by procedures substantially similar to competitive sealed bidding or competitive sealed proposals and AS 36.30 does not apply to the awarding of the grant, contract, or lease.

(b) If a state grant, contract, lease, or loan is awarded by or for a public corporation, board, or commission within a department but not by or for the office of the commissioner of that department, then an employee of the office of the commissioner in that department is not considered to be employed by the administrative unit awarding the grant, contract, lease, or loan.

(c) For purposes of AS 39.52.150(b)(1), if the public officer was not employed by the administrative unit at the time a state grant, contract, or lease was competitively solicited, the officer's subsequent employment by that administrative unit does not constitute a violation of AS 39.52.150 unless the officer takes or withholds official action with respect to the administration of the grant, contract, or lease.

(d) For purposes of AS 39.52.150(c), a loan is not subject to fixed eligibility standards if the award of the loan is subject to review for adequacy of security or other discretionary judgment concerning repayment ability. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.150 AS 39.52.950

9 AAC 52.090. OUTSIDE EMPLOYMENT OR SERVICE. For purposes of AS 39.52.170, a public employee's outside employment or service, including volunteer service, is incompatible or in conflict with the proper discharge of official duties if the employee's designated supervisor reasonably determines that the outside employment or service

(1) takes time away from the employee's official duties;

(2) limits the scope of the employee's official duties; or

(3) is otherwise incompatible or in conflict with the proper discharge of the employee's official duties. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.170 AS 39.52.950

9 AAC 52.100. RESTRICTIONS ON EMPLOYMENT AFTER LEAVING STATE SERVICE. (a) For purposes of AS 39.52.180(a), "matter" does not include the general formulation of policy by a public official.

(b) For purposes of AS 39.52.180(a), routine processing of documents, general supervision of employees without direct involvement in a matter, or ministerial functions not involving the merits of a matter under consideration by an administrative unit do not constitute personal or substantial participation in a matter by a public officer. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.180 AS 39.52.950

9 AAC 52.110. ETHICS FILES. (a) A designated supervisor shall maintain an ethics file containing Ethics Act reports, advisory opinions, advisory opinion requests, complaints, disclosures, and determinations relevant to that supervisor's agency or administrative unit.

(b) A designated supervisor shall segregate confidential material from other ethics file material that is available for public inspection.

(c) An executive director of a board or commission may maintain the ethics file of the chair of the board or commission. The ethics file of the chair of a board or commission may be combined with the ethics file of the designated supervisor of the staff of the board or commission. (Eff. 4/29/94, Register 130)

Authority: AS 39.52.210 AS 39.52.230
AS 39.52.220 AS 39.52.950

9 AAC 52.120. DECLARATION OF POTENTIAL VIOLATION BY MEMBER OF A BOARD OR COMMISSION. (a) A declaration by a member of a board or commission of the facts and circumstances about a matter that may result in a violation of AS 39.52.110 —

AS 39.52.190 or this chapter may serve as the disclosure in writing to the designated supervisor required by AS 39.52.220 if

(1) the declaration is made at a recorded public meeting of each board and commission on which the member serves;

(2) a tape or transcript of each meeting is preserved in accordance with the records retention schedule of the board or commission; and

(3) a method for identifying each portion of tape or transcript containing the declaration is used and the identifications are preserved.

(b) A member of a board or commission who takes or withholds an action that violates the Ethics Act or this chapter will not be held liable under the Ethics Act for the action if

(1) the action is taken or withheld in accordance with a determination by the chair as designated supervisor or the board under the procedures set out in AS 39.52.220;

(2) the member fully discloses all facts reasonably necessary to the determination of the chair or the board; and

(3) the attorney general has not advised the member, chair, board, or commission that the action violates the Ethics Act or this chapter. (Eff. 4/29/94, Register 130)

Authority: AS 39.52.220 AS 39.52.240(d) AS 39.52.950

9 AAC 52.130. DESIGNATED SUPERVISOR'S REPORT. (a) A designated supervisor shall submit the quarterly report described in AS 39.52.260 during the 45 days following the end of each calendar quarter.

(b) An executive director of a board or commission may file a quarterly report on behalf of the chair of the board or commission. The quarterly report filed on behalf of a chair and the quarterly report of a designated supervisor of the staff of a board or commission may be combined into one report.

(c) If a board or commission does not meet during a calendar quarter, and the designated supervisor of the board or commission notifies the attorney general that no meeting, or activity reportable under the Ethics Act or this chapter, occurred during the calendar quarter, than neither the chair nor the designated supervisor of the staff must file a report for the board or commission for the quarter. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.260 AS 39.53.950

9 AAC 52.140. COMPLAINTS. (a) The attorney general will, in the attorney general's discretion, conduct a preliminary ethics investigation before initiating or accepting a complaint. A preliminary ethics investigation and information discovered in the course of a preliminary ethics investigation is confidential to the same extent as information discovered in an ethics investigation conducted after the acceptance of a complaint.

(b) The attorney general will, in the attorney general's discretion, refer a complaint to the subject's designated supervisor under AS 39.52.310(e) and, at the same time, accept the complaint for an ethics investigation under AS 39.52.310(f) and (g).

(c) If the attorney general refers a complaint under AS 39.52.310(e) and the designated supervisor determines that a violation of the Ethics Act or this chapter has occurred, the designated supervisor shall forward those findings to the attorney general for review under AS 39.52.310 — AS 39.52.350.

(d) If an ethics complaint does not allege a violation of the Ethics Act or this chapter by the governor, lieutenant governor, or attorney general but, in the course of an ethics investigation, evidence of a potential violation by the governor, lieutenant governor, or attorney general is discovered, then the attorney general will refer the matter to the personnel board. The personnel board shall retain independent counsel in the same manner as if the complaint initially alleged those violations. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.310 AS 39.52.950

9 AAC 52.150. PERSONNEL BOARD NOTIFICATION. If independent counsel appointed under AS 39.52.310(c) recommends action under AS 39.52.330, the independent counsel shall notify the personnel board that action to correct or prevent a violation of the Ethics Act or this chapter has been recommended. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.330 AS 39.52.950

9 AAC 52.160. CONFIDENTIALITY. (a) The attorney general will keep confidential the information obtained in the course of an ethics investigation that is not relevant to an accusation or subsequent ethics proceedings.

(b) The attorney general will, in the attorney general's discretion, forward information obtained in the course of an ethics investigation to the subject's designated supervisor or other appropriate superior for potential disciplinary action under AS 39.52.420. Information forwarded under this subsection remains confidential, and the subject's designated supervisor or other appropriate superior may share the information only with a person who needs to know the information to consider potential disciplinary action.

(c) A subject may not partially waive the confidentiality protection of AS 39.52.340 or this chapter.

(d) Nothing in AS 39.52.340 or this section prevents a person from disclosing to a third person information the person learned independent of the investigation conducted by the attorney general, unless prohibited by other laws.

(e) Nothing in this section prevents either the attorney general from withholding or a person from objecting to the release of information or materials in the possession of the attorney general on a legal ground other than one provided by AS 39.52.340.

(f) If, after an ethics investigation, the attorney general does not initiate formal proceedings, then information and material discovered in the course of the ethics investigation, as well as the existence of the ethics investigation, must remain confidential unless disclosure is otherwise permitted under the Ethics Act or this chapter.

(g) If the attorney general determines that a crime may have been committed or may be committed, the attorney general will, in the attorney general's discretion, release information obtained in a confidential ethics matter to an appropriate law enforcement agency. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.340 AS 39.52.420 AS 39.52.950

9 AAC 52.170. CIVIL PENALTIES FOR MULTIPLE VIOLATIONS. If one act violates more than one provision of the Ethics Act, a civil penalty may be imposed for each provision violated. A civil penalty may be imposed each time a provision of the Ethics Act is violated. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.440 AS 39.52.950

9 AAC 52.180. ATTORNEY GENERAL REVIEW OF AGENCY POLICIES. The attorney general will approve a written policy described in AS 39.52.920 if it is consistent with and furthers the purposes of the Ethics Act and this chapter. As a condition of approval, the attorney general will require that the policy be distributed to employees of the agency and to new employees of the agency upon employment, and require that the policy be centrally posted in the agency's offices. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.920 AS 39.52.950

9 AAC 52.990. DEFINITIONS. (a) In AS 39.52.410, "blind trust" means a trust established under AS 39.50.040.

(b) In the Ethics Act and in this chapter

(1) "board or commission" has the meaning given in AS 39.52.960 and does not include an entity created under only a federal statute or other non-state action;

(2) "Ethics Act" means Alaska Executive Branch Ethics Act (AS 39.52);

(3) "executive director" includes an executive secretary to a board or commission under AS 08 or the marine pilot coordinator under AS 08.62.050;

(4) "improper motivation" means a motivation not related to the best interests of the state, and includes giving primary consideration to a person's

(A) kinship or relationship with a public officer;

(B) financial association with a public officer;

(C) potential for conferring a future benefit on a public officer; or

(D) political affiliation;

(5) "person" has the meaning given in AS 39.52.960 and includes governmental entities;

(6) "personal gain" means a benefit to a person's or immediate family member's personal interest or financial interest;

(7) "public employee" has the meaning given in AS 39.52.960 and includes a permanent employee of an agency on non-seasonal leave without pay status, but does not include an individual on layoff status, a seasonal employee of an agency during the period of time that the employee is not employed by the agency, or a temporary employee of an agency during the period of time that the employee is not employed by the agency;

(8) "state contract" includes employment with the state, regardless of whether that employment is evidenced by a written agreement, but does not include a license or other authorization from the state to do business or to perform a particular activity in the state; and

(9) "subject" means an individual who either

(A) is being investigated for a potential violation of the Ethics Act or this chapter; or

(B) is the individual against whom a complaint is filed under the Ethics Act or this chapter. (Eff. 4/24/94, Register 130)

Authority:	AS 39.52.120(a)	AS 39.52.950
	AS 39.52.410	AS 39.52.960

ALASKA ADMINISTRATIVE CODE

Title 9

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Chapter 52. Executive Branch Code of Ethics.

9 AAC 52.010. Appearance of impropriety. An appearance of impropriety does not establish that an ethical violation exists. (Eff. 4/24/94, Register 130)

Publisher's note: The history line for this regulation is set out above, as of Register 135 (October 1995), pursuant to directions from the Department of Law, in order to correct the effective date.

9 AAC 52.060. Gifts. (a) As used in the Ethics Act and this chapter, a gift is a transfer or loan of property or provision of services to a public officer for less than full value. Unless rebutted by other evidence, an occasional gift worth $50 or less is presumed not to be given under circumstances in which it could be reasonably inferred that the gift is intended to influence an officer's performance of official duties, actions, or judgment.

(b) For purposes of AS 39.52.130, travel or lodging of any value received by a public officer in connection with a trip that the public officer takes as part of the officer's official duties is not an improper gift if the monetary value of the travel or lodging is comparable to the cost that the state would have had to pay for the travel or lodging and

(1) the head of the officer's agency determines that the gift is to the state, not to the officer; or

(2) the travel or lodging is incidental transportation by or hospitality at the residence of an individual. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.130 AS 39.52.950

Publisher's note: This regulation is set out above, as of Register 133 (April 1995), pursuant to directions from the Department of Law, in order to correct a typographical error in the second sentence in (a).

9 AAC 52.070. Information disseminated to the public. (a) For purposes of AS 39.52.140, information has been disseminated to the public if it has been published through newspaper publication; broadcast media; a press release; a newsletter; a legal notice; a nonconfidential court filing; a published report; a public speech; or public testimony before the legislature, a board, or a commission.

(b) Information that is available to the public but that has not been published as described in (a) of this section has not been disseminated to the public. (Eff. 4/24/94, Register 130)

Authority: AS 39.52.140 AS 39.52.950

Publisher's note: This regulation is set out above, as of Register 153 (April 2000), pursuant to directions from the Department of Law, in order to correct a typographical error in 9 AAC 52.070(a).

9 AAC 52.110. Ethics files. (Eff. 4/24/94, Register 130)

Publisher's note: The history line for this regulation is set out above, as of Register 135 (October 1995), pureuant to directions from the Department of Law, in order to correct the effective date.

9 AAC 52.120. Declaration of potential violation by member of a board or commission. (Eff. 4/24/94, Register 130)

Publisher's note: The history line for this regulation is set out above, as of Register 135 (October 1995), pursuant to directions from the Department of Law, in order to correct the effective date.

Alaska Department of Environmental Conservation

Amendments to:
State Air Quality Control Plan

Vol. III: Appendix III.C.3.
Base Year Emission Inventory Comparison

{Appendices to:
Volume II, Section III.C Fairbanks Transportation Control Program}.

Public Review Draft

March 17, 2014

Sean Parnell, Governor

Larry Hartig, Commissioner

(This page serves as a placeholder for two-sided copying)

November 20, 2012

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Memo to: Cindy Heil, ADEC

From: Tom Carlson and Bob Dulla

Subject: Summary of Inventory Revisions to the 2008 Fairbanks CO Maintenance Plan

Since the development of the 2008 Fairbanks CO Maintenance Plan (MP), several methodological revisions have been applied and updated activity data were obtained that supersede elements of the CO inventory reflected in that earlier plan. These are summarized briefly in this memorandum.

The revisions/updates to the CO inventory in the 2008 Plan are listed below and grouped by inventory sector: on-road mobile, non-road mobile, area, and point.

On-Road Mobile

Vehicle emissions were estimated for the Fairbanks modeling area using EPA's MOVES (Motor Vehicle Emission Simulator). The analysis was based on the MOVES2010b version released in June 2012. MOVES is the successor to EPA's MOBILE series of on-road vehicle emissions models. It can be used to estimate exhaust and evaporative emissions as well as brake and tire wear emissions from all types of on-road vehicles. Compared to MOBILE6.2, MOVES incorporates substantial new emissions test data and accounts for changes in vehicle technology and regulations as well as an improved understanding of in-use emission levels and the factors that influence them.

Modeling Approach – The basic approach in applying MOVES to calculate vehicle emissions for the nonattainment area was based on MOVES technical modeling guidance developed by EPA[1] for use in SIP and regional conformity analyses. In accordance with that guidance, MOVES was executed for the four-month (November through February) winter CO season that corresponds to the period in which violations of the ambient standard may occur in Fairbanks. Per EPA's guidance, MOVES was also executed on an hourly time-scale to more accurately reflect diurnal variations in travel and ambient conditions that can affect vehicle emissions.

[1] "Technical Guidance on the Use of MOVES2010 for Emission Inventory Preparation in State Implementation Plans and Transportation Conformity," U.S. Environmental Protection Agency, Office of Transportation and Air Quality, EPA-420-B-10-023, April 2010.

For SIP and conformity analysis, MOVES must be executed using the County Domain/Scale option. (MOVES can also be executed in National Scale and Project Scale modes.) For regional conformity analyses using MOVES County Scale option, EPA's guidance essentially directs users to input a detailed series of data that replace nationwide-based default values with vehicle fleet, travel activity, and other parameters that represent the county or region being modeled.

MOVES was executed for the Fairbanks, Alaska geographic area to produce estimates of CO emissions. Discussions of the development of the detailed MOVES inputs in accordance with EPA's MOVES SIP development guidance are presented below.

Vehicle Populations (Source Type Population & Age Distribution) − Vehicle registrations from the Alaska Division of Motor Vehicles (DMV) and recent Alaska Parking Lot Survey data conducted by ADEC provided the basis for the vehicle fleet populations and age distributions used to model the Fairbanks vehicle fleet with MOVES. The DMV data were obtained through ADEC from a "dump" of the statewide registration database as of May 2010. The DMV database includes vehicle make, model, model year, Vehicle Identification Number (VIN), vehicle class code, body style, registration status, and expiration date.

Using a VIN decoding tool licensed by ADEC, supplemental information such as vehicle class, gross vehicle weight, vehicle type, body type, and fuel type (e.g., gasoline vs. diesel) were also determined in order to help classify each vehicle into one of the 13 MOVES Source Types. Key vehicle attribute fields from the DMV database and VIN decoder outputs were used to categorize each vehicle record into one of the 13 usage-based "Source Type" categories as defined in MOVES to characterize the vehicle fleet.

Gasoline vs. Diesel-Fueled Vehicle Fractions (AVFT Strategies) – MOVES provides users the ability to override its default nationwide-based travel splits between different fuels and technologies. These Alternative Vehicle Fuel and Technology (AVFT) inputs are supplied to MOVES2010b through the County Data Manager.

In order to account for differences in splits between gasoline- and diesel-fuel vehicles in the Fairbanks fleet compared to the U.S. as a whole, fuel fraction tables by source type and model year were also constructed using the DMV VIN decoded data described earlier. Not surprisingly, the MOVES default splits between gasoline and diesel vehicles were not representative of the Fairbanks fleet. Generally speaking, gasoline fractions were found to be lower in Fairbanks than the nationwide-based MOVES defaults (and diesel fractions were commensurately higher).

Travel Activity (Vehicle Type VMT) – Estimates of VMT over the expanded transportation modeling network (covering the entire CO nonattainment area) from the TransCAD travel model link output files were processed and input to MOVES through the "Vehicle Type VMT" input within the County Data Manager. The Vehicle Type VMT input must be in units of VMT per year, not VMT per day. The annual VMT must also be supplied by "HPMS Vehicle Type," which is essentially an aggregated version of the 13-category MOVES Source Type scheme. Since states are required to provide periodic travel (i.e., VMT) estimates to FHWA via the Highway Performance Monitoring System (HPMS), EPA has designed MOVES to accept VMT input by these HPMS

Vehicle Type categories. Link-level TransCAD model output files from the transportation modeling performed by FMATS for a 2010 base year and a 2035 forecast were processed to prepare these MOVES inputs for each analysis year. The 2010 TransCAD outputs were used directly to represent VMT for the 2010 analysis year. For analysis years 2011 through 2015, VMT was linearly interpolated from the 2010 and 2035 TransCAD outputs (which exhibited an annual VMT growth rate of roughly 1.0%). For analysis years 2005 through 2009, total VMT was back-casted from the 2010 TransCAD outputs based on historically developed regional VMT estimates supplied by ADOT&PF.

The TransCAD outputs encompasses a modeling domain that extends beyond the CO nonattainment area. Spatial processing performed during the development of the TransCAD outputs was used to identify whether each link was within or outside the smaller CO nonattainment area. The VMT estimates for this analysis were based on the subset of links within the CO nonattainment Area.

Annual mileage per vehicle estimates by HPMS Vehicle Type were extracted from MOVES2010b nationwide default model runs and were used in conjunction with travel model VMT splits between Passenger and Truck VMT to apportion total VMT output by TransCAD into the six HPMS Vehicle Type categories required by MOVES.

Other MOVES Inputs – The remaining MOVES modeling inputs representing the Fairbanks CO nonattainment area included seasonal, daily, and diurnal travel fractions; travel activity by speed range (or bin) and roadway type; freeway ramp fractions; ambient temperature profiles; I/M program inputs; and fuel specifications. Each of these inputs was supplied to MOVES to represent Fairbanks-specific conditions through the model's County Data Manager Importer and is discussed separately below.

Monthly, Day-of-Week, and Hourly VMT Fractions – In conjunction with annual VMT by HPMS Vehicle Type, MOVES also requires inputs of monthly, weekday/weekend, and hourly travel fractions. Based on data assembled by ADOT&PF from 2009 seasonal traffic counts, traffic within the CO nonattainment area portion of the FMATS modeling area exhibits a seasonal variation such that roughly 93% of annual average daily travel occurs on average winter days (with 107% occurring on average summer days). These seasonal variations were incorporated into the MonthVMTFraction input table.

Day-of-week fractions were set to assume that travel levels are the same on weekends as weekdays. In the absence of a weekend or seven-day travel model, this is a reasonable assumption.

Hourly VMT fractions were defined based on diurnal trip percentages used to support the travel model development and validation that are listed in Appendix C.

Travel by Speed Bin and Roadway Type (Average Speed Distribution & Road Type Distribution) – The link-level TransCAD model output files described earlier were processed to develop average speed and road type distribution inputs, respectively.

The roadway type classification scheme employed in MOVES consists of the following five categories:

1. Off-Network;
2. Rural, Restricted Access;
3. Rural, Unrestricted Access;
4. Urban, Restricted Access; and
5. Urban, Unrestricted Access.

The “Off-Network” category is used by MOVES to represent engine-off evaporative or starting emissions that occur off of the travel network. For SIP and regional conformity analysis, EPA’s MOVES guidance indicated that the user must supply Average Speed Distribution and Road Type Distribution inputs for the remaining on-network road types (2 through 5), but direct MOVES to calculate emissions over all five road types. In this manner, starting and evaporative emissions are properly calculated and output.

The first of the two sets of inputs, Average Speed Distributions, consists of time-based[2] (not distance-based) tabulations of the fractions of travel within each of MOVES’ 16 speed bins (at 5 mph-wide intervals) by road type and hour of the day. These inputs were calculated from the TransCAD link outputs by time of day. The TransCAD outputs consisted of travel times, average speeds, and vehicle volumes for each link in the expanded modeling network for each of three daily periods:

1. AM Peak (7-9 AM);
2. PM Peak (3-6 PM); and
3. Off-Peak (9 AM-3 PM, plus 6 PM-7 AM).

Spreadsheet calculations were performed on the TransCAD link outputs to calculate time-based travel (multiplying link travel time by vehicle volume to get vehicle hours traveled or VHT) across all links. The link VHT was then allocated by MOVES road type and average speed bin. (The link classification scheme employed in the TransCAD modeling could easily be translated to the MOVES Rural/Urban and Limited/Unlimited Access road types.) Normalized speed distributions (across all 16 bins) were then calculated for each road type and time of day period and formatted for input into MOVES.

These distributions were very similar for the 2010 and 2035 TransCAD outputs. Distributions for each analysis year (2005-2015) were developed by straight-line interpolation/extrapolation of the nominal trends in the 2010 and 2035 TransCAD-based distributions.

MOVES allows the Average Speed Distribution inputs to be specified separately by Source Type (i.e., vehicle category). Thus, individual distributions were developed from Passenger VHT and Truck VHT tabulations of the TransCAD outputs. The Passenger VHT was available for each of the three modeling periods. Truck VMT was only available on a single daily basis.

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[2] MOVES requires Average Speed Distribution inputs on a time-weighted basis and Road Type Distribution inputs on a distance-weighted basis.

Freeway Ramp Fractions (Ramp Fraction) – MOVES uses default values of 8% (or 0.08) to represent the fraction of time-based limited access roadway travel (Road Types 2 and 4) that occurs on freeway ramps. Fairbanks-specific ramp fraction values were tabulated from the TransCAD link level outputs and were supplied to MOVES in the Ramp Fraction input section of the County Data Manager to override the nationwide-based defaults. The Fairbanks ramp fractions in urbanized areas are higher than the default values in MOVES, reflecting the fact that shorter freeway lengths (with resulting higher ramp fractions) are driven in Fairbanks compared to the nationwide-based defaults.

Ambient Temperature Profiles (Meteorology Data) – Monthly average diurnal (i.e., hour-by-hour) ambient temperature and humidity profiles compiled by EPA for each county in the U.S. and contained in MOVES' default database were used for the emission modeling runs. According to EPA guidance, these ambient meteorology data profiles were compiled from 30 years (1971-2000) of daily temperature and humidity data. The profiles for Fairbanks (ZoneID=20900) are based on the station at the Fairbanks International Airport. The ambient temperatures range from +11.7°F in November (Hour 16) down to -16.1°F in January (Hour 5). Relative humidity ranged from 48% to 82%.

Profiles for each of the winter months modeled were exported from the MOVES database and input via the County Data Manager.

I/M Program Data (I/M Programs) – Since the Fairbanks I/M program was terminated at the end of 2009, the "Use I/M Program" input element to MOVES for the 2010-2015 analysis years was set from "Yes" to "No" to account for the elimination of the program. A compliance rate of 96% was modeled based on the latest parking lot survey data.

Fuel Specifications (Fuel Supply) – EPA has developed detailed fuel specifications (e.g., RVP, oxygen content, sulfur content, etc.) for different gasoline and diesel fuel blends used in each county of the U.S. and has loaded these specifications into the *FuelFormulation* and *FuelSupply* tables in the MOVES default database. (The first of these tables identifies the detailed properties of a specific fuel blend; the second table identifies the state and county of the U.S. and the calendar year to which it applies.) Semi-annual fuel survey data collected by the Alliance of Automobile Manufacturers (AAM) were reviewed to confirm whether the default fuel properties for Fairbanks defined in MOVES were correct. Retail gasoline data for the 2008 winter for Fairbanks from the AAM surveys indicated that sulfur and oxygen contents in MOVES reasonably matched measured levels.

However, Fairbanks diesel blends are not included in the AAM surveys. MOVES assumed diesel fuel sulfur content of 43 ppm in 2008 through 2011 and 11 ppm in 2012 and later years. These sulfur levels are believed to be reasonably representative of those required under Alaska's Ultra Low-Sulfur Diesel (ULSD) regulation.

Thus, MOVES default gasoline and diesel fuel specifications for Fairbanks were used in the analysis.

Non-Road Mobile

The non-road inventory was based on updated modeling with EPA's NONROAD model for recently developed "Big 3" criteria pollutant inventories that were generated for Anchorage, Fairbanks, and Juneau. Key revisions included a substantial increase in snowmobile emissions based on locally collected snowmobile population estimates, rather than NONROAD model defaults. Base year estimates from that effort were combined with updated aircraft inventory estimates and railroad emission estimates developed in support of the Fairbanks $PM_{2.5}$ SIP.

Area

Area source estimates were also updated based on emissions compiled for the Fairbanks $PM_{2.5}$ SIP. Key revisions were focused within the space heating sector (primarily wood-burning emissions) based on locally collected activity data and heating device emission testing data supporting the $PM_{2.5}$ SIP development. Historical and forecasted population trends from that effort were also used to develop the updated area source CO estimates.

Point

Point source estimates were updated on a facility-specific basis where data were available from the $PM_{2.5}$ SIP development. Similar population-based trends applied to the area sources were also used to project base year 2008 point source emissions obtained for the $PM_{2.5}$ SIP.

Summary

Table 1 summarizes the emission changes described above, comparing each of the source categories in 2005, 2010, and 2015. Adjustments for additional control measures included in each MP are also incorporated so that the final inventory values can be contrasted. The table shows that emission estimates for all of the source categories changed between the two inventories. As described above, the changes are the result of new insights from surveys, updated activity forecasts, and model revisions. The most significant of these are as follows:

- Use of MOVES2010b (which has higher per-vehicle emission rates than MOBILE6 at cold temperatures);

- Higher residential wood burning emissions in the area source sector based on emission testing and updated activity data collected in support of the Fairbanks $PM_{2.5}$ SIP; and

- Higher nonroad emissions based on an upwardly adjusted snowmobile population reflected in Alaska's latest criteria pollutant inventories for Fairbanks (the earlier estimates had been based on default populations estimated for Fairbanks in an earlier version of EPA's NONROAD model).

Table 1
Comparison of Source Category Emissions
Between 2008 and Current CO Maintenance Plans
(Tons/Day)

Source Category	2008 Maintenance Plan			Current Maintenance Plan		
	2005	2010	2015	2005	2010	2015
On-Road	24.98	21.25	19.15	45.48	43.48	45.19
Nonroad	3.04	3.40	3.62	14.80	15.97	16.79
Area	0.58	0.62	0.65	19.69	21.28	22.38
Point	3.08	3.29	3.44	3.09	3.34	3.51
Total	**31.69**	**28.56**	**26.87**	**83.06**	**84.08**	**87.87**

If you have any questions about the information presented above, please do not hesitate to contact us.

Alaska Department of Environmental Conservation

Amendments to:
State Air Quality Control Plan

Volume III: Appendix III.K.6
Best Available Retrofit Technology (BART) Documentation

{Appendix to Volume II, Section III.K:
Area-wide Pollutant Control Program for Regional Haze}

Public Review Draft

March 17, 2014

Sean Parnell, Governor

Larry Hartig, Commissioner

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APPENDIX III.K.6

BART Documentation

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CONTENTS:

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF AIR QUALITY
AIR PERMITS PROGRAM

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December 19, 2007

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Subject: CALMET Modeling Protocol Addendum – Approval

Dear Members of the Alaska BART Coalition:

The Alaska Department of Environmental Conservation (Department) is approving the Alaska BART Coalition's (Coalition's) CALMET modeling protocol, as amended December 17, 2007. The amendment adequately addresses the concerns raised in the Department's December 4, 2007 letter regarding the Coalition's original CALMET modeling protocol. The amendment is also consistent with the decisions made during the December 13, 2007 teleconference between Coalition members (and their consultants), the U.S. Fish and Wildlife Service (FWS), the National Park Service (NPS), and the Department.[1] The Coalition may proceed with running CALMET as described in the December 17, 2007 amendment.

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[1] Region 10 of the U.S. Environmental Protection Agency (R10) was unable to participate in the December 13, 2007 teleconference, but has been kept apprised of the issues and amendment.

Please contact me if you have any questions regarding this finding. I may be reached at the above address, via e-mail at alan.schuler@alaska.gov, or phone at (907) 465-5112.

Sincerely,

Alan E. Schuler

Alan E. Schuler, P.E.
Environmental Engineer

cc: Bart Brashers, Geomatrix
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Al Trbovich, Hoefler Consulting
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Rebecca Smith, ADEC/APP, Juneau
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Alaska CALMET Modeling Protocol

Alaska CALMET Modeling for BART
Southern Alaska

Prepared for:

Members of the Alaska BART Coalition:

Agrium Inc.
Alyeska Pipeline
Anchorage Municipal Light and Power
ConocoPhillips Alaska, Inc
Tesoro Alaska Company

September 2007

Project No. 013474

Alaska CALMET Modeling Protocol

Alaska CALMET Modeling for BART
Southern Alaska

Prepared for:

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Anchorage Municipal Light and Power
ConocoPhillips Alaska, Inc
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September 2007

Project No. 013474

MODELING PROTOCOL
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1. INTRODUCTION

The Alaska Department of Environmental Conservation (ADEC) is developing a plan to protect visibility and comply with the United States Environmental Protection Agency's (EPA's) Clean Air Visibility Rule. A component of this plan is the implementation of the Best Available Retrofit Technology (BART) rules in Alaska.[1] According to the *BART Guidelines*, each state may determine which BART-eligible sources are "subject to BART" using the CALPUFF dispersion model. If it is determined that sources are "subject to BART," the CALPUFF model can also be used to assess the efficacy of pollution controls considered for BART. The CALPUFF model is run using a meteorological dataset developed with the CALMET program. This modeling protocol discusses techniques for the application of CALMET to prepare a three-year meteorological dataset to be used for BART simulations.

1.1 BACKGROUND

On behalf of ADEC, The Western Regional Air Partnership (WRAP) conducted CALPUFF simulations of Alaska BART-eligible sources. The simulations were performed to evaluate whether these eligible sources are subject to a BART Determination based on predicted impacts to visibility within Alaska Class I areas. BART-eligible sources are exempt from performing a BART Determination if their impacts are below screening criteria set by ADEC, EPA, and the Federal Land Managers (FLMs). Non-exempt sources must perform a technology review and propose BART for each emission unit that comprises the BART-eligible source.

WRAP used the CALPUFF modeling system to assess the impacts from BART-eligible sources in Alaska based on a single year of CALMET processed data for 2002.[2] CALMET was applied to process a meteorological simulation of Alaska weather using the Fifth Generation Mesoscale

[1] EPA published the Best Available Retrofit Technology (BART) standards under the Regional Haze Rule on July 6, 2005. Appendix Y, "Guideline for Best available Retrofit Technology Determination" (the BART Guideline) details EPA's recommendations to states for conducting BART analyses.

[2] The WRAP CALPUFF modeling procedures and results for Alaska and other western states are available at http://pah.cert.ucr.edu/aqm/308/bart.shtml.

Model (MM5), developed and maintained by the Pennsylvania State University (PSU) and the National Center for Atmospheric Research (NCAR).[3]

WRAP used MM5 to simulate the weather during calendar year 2002, using two computational domains with 45 and 15 km grid spacing, respectively. The CALPUFF model grid spacing was 2 km, significantly smaller than the MM5 grid spacing of 15 km. In addition, because only one year was simulated, BART exemption simulations performed by WRAP used the highest modeled visibility impact, not the 98th percentile impact as recommended under EPA rules. By using a full three years of MM5 data processed by CALMET using the procedures described in this protocol, it is expected that the 98th percentile impact will be used to assess the visibility impacts.

1.2 NEW CALMET PROTOCOL

Geomatrix, and our subcontractor 3TIER, were contracted by an ad-hoc Alaska BART Coalition (a collection of corporations with BART-eligible sources) to perform a refined MM5 simulation of Alaska, as well as post-process the MM5 data and prepare CALMET files in support of CALPUFF modeling. The MM5 simulations used a nested grid with mesh sizes of 45, 15 and 5 km and covered the three-year period of 2002 to 2004. The MM5 modeling techniques are described in a MM5 Protocol[4] and the simulations are compared to observations in a MM5 Modeling Report.[5]

This protocol describes the processing planned for the MM5 simulations by CALMM5 and CALMET for use in future BART CALPUFF assessments that might be conducted by BART Coalition members. The three-year MM5 dataset with an inner 5-km mesh size domain improves the basis of the meteorological fields used to assess visibility in Class I areas and allows the application of the more robust 98th percentile change to extinction as the BART exemption criterion. Further, the 5-km grid provides a valuable tool in the form of refined meteorological data input fields that may be used for future modeling studies in south-central Alaska.

---

[3] WRAP MM5 Protocol: *Alaska MM5 Modeling For The 2002 Annual Period To Support Visibility Modeling*, September 2005. The protocol is available at http://pah.cert.ucr.edu/aqm/308/docs/alaska.

[4] Geomatrix, 2007. *Alaska MM5 Modeling Protocol, Alaska MM5 modeling for BART in Southern Alaska*. Geomatrix, 3500 188th Street SW, Suite 600, Lynnwood, WA, May 2007.

[5] Geomatrix, 2007. *Alaska MM5 Modeling Report, Alaska MM5 modeling for BART in Southern Alaska*. Geomatrix, 3500 188th Street SW, Suite 600, Lynnwood, WA, September 2007.

2. MODEL SELECTION

The *BART Guideline* recommends the use of the CALPUFF modeling system to establish whether a stationary source is reasonably anticipated to cause or contribute to haze in Federal Class I areas. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility.

CALMET is the meteorological component of the CALPUFF modeling system. Geomatrix will apply the latest regulatory version of CALMET (Version: 5.8, Level: 070623) to prepare the meteorological datasets for future CALPUFF simulations. This version of CALMET is significantly different than Version: 6.211 (Level: 060414) used by WRAP in the earlier BART simulations. CALMET Version 5.8 corrects the known errors contained in Version 6.211 and more closely corresponds to earlier codes that have been recommended by the EPA for many years.

3. MODELING DOMAIN

Geomatrix will use the modeling domain shown in Figure 2 for the CALMET datasets. The domain encompasses the BART-eligible sources and Class I areas of interest: Denali National Park and the Tuxedni Wilderness. The 540 km-by-650 km CALMET domain has a grid size of 2 km and is essentially the study area used by WRAP in early BART simulations of Alaska. Geomatrix has shifted the domain slightly to more closely correspond to the inner MM5 D03 domain shown in Figure 1. The CALMET domain will use a Lambert Conformal Conic (LCC) coordinate system centered at (59ºN, 151ºW) with standard latitudes of 30ºN and 60 ºN. This is the same coordinate system used by WRAP. The proposed domain extends from LCC coordinates (-210,-20) to (330,630) km.

Geomatrix prepared land use and terrain data from the North American 30 second datasets that accompany the CALPUFF modeling system using the geophysical pre-processor tools included in the system. Figure 2 and Figure 3 show the resulting 2-km mesh size fields for terrain and land use, respectively. Many of the algorithms in CALMET differ in the characterization of over-water versus over-land boundary layer processes. In addition, when buoy data are used it is necessary to further distinguish between the marine water bodies and inland lakes. In order to accurately characterize the boundary of the marine environment, Geomatrix employed the coastline processing option in the geophysical pre-processors TERREL and CTGPROC. These programs use the USGS Global Self-consistent Hierarchical High-resolution Shoreline (GSHHS) database.[6]

4. AVAILABLE METEOROLOGICAL DATA

CALMET can use both MM5 simulations and observations to construct the meteorological data required by the CALPUFF model. Although the MM5 simulations can be used to provide all the necessary data, EPA Region 10 and the FLMs recommend observations also be used to the extent possible.[7] CALMET can use a variety of observational datasets including: upper-air soundings, surface weather observations, hourly precipitation data, and offshore buoy measurements. The remainder of this section describes the available observations and the techniques planned to prepare these data for CALMET.

4.1 SURFACE WEATHER OBSERVATIONS

Surface weather observations provide hourly winds, temperature, relative humidity, pressure, cloud cover and ceiling height data to CALMET. Geomatrix will extract available surface observations from the University Center of Atmospheric Research (UCAR) ds472 dataset.[8] Geomatrix has developed a number of tools to extract observations from the UCAR ds472 dataset and reformat them for use by CALMET. This is the same database used previously by WRAP and Geomatrix to evaluate the MM5 simulations.[3,5] Geomatrix will add the National Park Service's meteorological station at Denali National Park headquarters to supplement the ds472 database. Figure 4 shows the location of 45 surface stations within and near the modeling domain. A list of these stations and the data availability for 2002 to 2004 is displayed in Table 1.

The data recoveries shown in Table 1 are based on the number of total observations in the dataset, not the number of valid measurements of each necessary variable. Depending on the CALMET options selected, there always must be at least one valid surface observation per hour. Geomatrix has selected the five stations: Big Delta (PABI), Elmendorf (PAED), McGrath (PAMC), Anchorage (PANC), and Seldovia (PASO) as "key stations" based on their locations and data recoveries for the necessary variables: temperature, relative humidity, pressure, cloud cover and ceiling height. When missing at these sites, these variables will be

[6] The GSHHS database is described and can be obtained at http://www.ngdc.noaa.gov/mgg/shorelines/gshhs.html.
[7] Wong, Herman, 2007. *CALMET V5.8 Template.* Email from Herman Wong, EPA Region 10 to Ken Richmond Geomatrix, August 23, 2007. EPA's specific recommendations for CALMET in Region 10 are listed in Appendix B of this protocol.

[8] Dataset ds472.0, *TDL U.S. and Canada Surface Hourly Observations*. http://dss.ucar.edu/datasets/ds472.0

filled in assuming persistence. Missing wind observations will not replaced using this technique, because the options discussed in Section 6 allow for the use of MM5 surface winds in combination with surface observations and it is not necessary to always have at least one surface wind measurement.

4.2 UPPER AIR SOUNDINGS

Upper air soundings can be used to provide wind and temperature data aloft to CALMET. Twice daily soundings during 2002 to 2004 are available from Anchorage (PANC) inside the modeling domain. Data are also available from McGrath (PAMC) and Fairbanks (PAFB) just outside the domain. The locations of these upper air sites are the same as the applicable surface stations shown in Figure 4. The data recovery for Anchorage, Fairbanks, and McGrath is close to 100 percent. Missing soundings must be filled in prior to the application of CALMET. In the past, Geomatrix has replaced missing soundings assuming persistence from the previous day or for long periods with a morning or afternoon monthly average sounding. This technique could be applied, but as discussed in Section 6, the upper air soundings will not be used to prepare the datasets.

4.3 HOURLY PRECIPITATION DATA

Hourly precipitation data are used by CALPUFF to characterize wet deposition processes. Hourly precipitation data for Alaska were provided by EPA Region 10 based on the TD-3240 (COOP) dataset from the National Climatic Data Center. Historical data from this dataset near the domain are available from the 39 stations shown in Figure 5. However only the four stations listed in Table 2 have consistent hourly observations during 2002 to 2004.

4.4 BUOY OBSERVATIONS

Options within CALMET can be selected to make a distinction between the marine and over-land boundary layer. Many characteristics over the water can be specified by the observations from the buoy dataset including: winds, air temperature, and air-sea temperature difference.

Geomatrix surveyed the National Data Buoy Center for available buoy data within and near the study domain.[9] Figure 6 and Table 3 show the locations of the buoys and the number of months of data available. Depending on the CALMET options selected, the buoy data are used to specify the air-sea temperature difference and air temperature of the entire portion of the domain classified as ocean in Figure 3. Most of the buoy data within the domain are collected

[9] Historical buoy observations can be obtained from the National Data Buoy Center at http://www.ndbc.noaa.gov/.

at locations within or near Prince William Sound. Buoy data are processed for CALMET using the BUOY utility. When used for air temperature over-water, there must always be at least one valid buoy measurement. Geomatrix will replace missing hourly periods of data from Buoy 46061 assuming persistence for periods less than a day and with the monthly average temperature for longer periods.

5. CALMM5 PROCEDURES

Geomatrix will apply CALMM5 (Version 2.7, level 061030) to convert raw MM5 output to a format readable by CALMET. Unlike older codes, this version of CALMM5 can read MM5v3 format files directly, and correctly performs the conversion from accumulated to hourly precipitation as it processes multiple MM5 files. The output is the newer 3D.DAT/2D.DAT format used by CALMET and several other models. The 3D.DAT files will include the entire MM5 D03 domain shown in Figure 1. This polar stereographic domain has a mesh size of 5 km and dimensions of 109-by-130 grid points. In order to conserve space and remove unused upper levels, only the lower 23 of 41 vertical levels will be retained for use by CALMET. The highest level (sigma = .5105) corresponds to about 4000 m above the MM5 terrain used to represent Mt. McKinley. A truncated sample CALMM5 "3D.DAT" is included in Appendix A.

Geomatrix will prepare a CALMM5 output file for each month using the corresponding 6-day MM5 simulations. The first and last 12-hours of each overlapping MM5 simulation will not be used.

6. CALMET PROCEDURES

CALMET, the meteorological preprocessor component of the CALPUFF system, will be used to combine the MM5 simulation data, surface observations, buoy observations, terrain elevations, and land use data into the format required by the dispersion modeling component CALPUFF. In addition to specifying the three-dimensional wind field, CALMET also estimates the boundary layer parameters used to characterize diffusion and deposition by the dispersion model.

EPA Region 10, the FLMs, and the state agencies of Washington, Oregon, and Idaho (hereafter the PNW states) recently issued a template of recommended options for CALMET regulatory analyses.[7] The options listed in the table included as Appendix B are based on a combination of the capabilities of CALMET Version 5.8, regulatory precedents, available MM5 simulations, and the observations available in the three PNW states.

Geomatrix proposes to apply most of the regulatory recommendations for PNW states to the Alaska CALMET procedures. However, the situation in Alaska is significantly different. In addition to the challenging physical setting and regional weather, the datasets available in Alaska are significantly different. The weather observations in Alaska are sparse and considering the varied terrain less representative of large geographic areas surrounding the sites. For the Alaska BART simulations, over-water transport is more important as many of the plumes from BART-eligible sources travel over Cook Inlet to reach the Tuxedni Wilderness.

The MM5 simulations also have different characteristics. The Alaska MM5 simulations have an inner domain with a 5-km mesh size versus the 12 km typically used for Class I assessments in the PNW states. The MM5 simulations used in these states are taken from an archive of prognostic forecasts from the University of Washington, whereas the MM5 simulations prepared for Alaska are based on a retrospective analysis. The Alaska MM5 simulations use four-dimensional data assimilation (FDDA), commonly called “nudging”, to guide the model to more closely mimic actual observations.

In general, the observations in Alaska are less representative and the MM5 simulations potentially better than commonly applied in the PNW states for Class I assessments. Considering these general concepts and based on examination of the results from several trial applications of CALMET, Geomatrix recommends a few modifications to the CALMET procedures used in the PNW states. Our recommendations for each CALMET variable are listed in Appendix B. The bases for our recommendations and further discussion follows:

- The MM5 simulations will be used to characterize upper level winds and temperature. A few twice daily soundings are not adequate to characterize hourly upper level meteorology. In addition, to some extent these soundings are already in the MM5 simulations as they are used indirectly to nudge the simulations. Upper level observations are also not recommended for CALMET in the PNW states.

- Local observed surface wind speed and wind direction will be blended with the MM5 simulations using the “no observations” option (NOOBS=1). Winds from both the buoy and surface observation network will be included. However, since the Alaska MM5 mesh size is smaller than used in the simulations for the PNW states, the radii of influence will be somewhat smaller: RMAX1=RMAX2= 15 km, and RMAX3= 20 km. In addition we propose to set R1=R2= 2.5 km and TERRAD= 5 km, slightly different than employed in the PNW states.

- The sparse Alaska precipitation observations will not be used in the CALMET application. Hourly precipitation will be based on the MM5 predictions (NPSTA= -1). The only hourly precipitation data within the domain is located in Anchorage as shown in Figure 5. Unlike winds, CALMET does not contain a method for directly including both the observations and MM5 predictions for precipitation. The work-around suggested for PNW states is to construct pseudo-measurement sites from MM5 predictions at every grid point. Data must be stripped from the CALMM5 files, reformatted, and combined with the true observations. This level of effort does not seem warranted given that the only data available in the domain are from Anchorage.

- Similarly, surface temperature observations from the buoy and surface station networks will not be used, by setting ITPROG= 2. Geomatrix proposes using the MM5 simulated surface temperatures. Since MM5 predictions are being used for the upper level temperatures, unrealistic lapse rates will be calculated by the model if the two sources are used simultaneously. In addition, interpolation of the surface observations over the land and the buoy measurement over the ocean results in physically unrealistic temperature fields. Further discussion on this topic is provided below.

- The new regulatory conformance switch MREG=1 will be selected to invoke EPA guidance for parameterization of the boundary layer of the ocean. This option is very sensitive to the air-sea temperature difference for the surface fluxes and the lapse rate aloft for the mixed layer height.

- Since buoy data are limited in space and availability during the three-year period, sea-surface temperatures (SSTs) and air-sea temperature difference will be based on the MM5 simulations (ITWPROG=2). SSTs in MM5 are not predicted, but specified as a boundary condition for the simulation. For the Alaska MM5 simulations, SSTs are specified on 1/4-by-1/4 degree grid based on a reanalysis of buoy observations, measurements from ships of convenience, and remote sensing from satellites. In the domain, this grid mesh size is about 14-by-28 km and the SSTs are updated daily from UCAR dataset ds277.7.[10]

- In our opinion, these ds277.7 data provide a much better characterization of SSTs than the sparse buoy network. The necessary over-water variables are now available to CALMET from MM5 with the application of newer versions of CALMM5. If this option is not used, for many periods in the three-year simulations these variables will use buoy data from Prince William Sound for the entire ocean portions of the domain. In addition, since the buoy datasets do not contain temperature lapse rate data near the mixed layer height, default settings are used to predict the mixed layer height. With ITWPROG = 2, MM5 temperatures aloft are used to derive the lapse rates over the water. Note, buoy winds will still be used for the construction of the surface wind field, but CALMET limits their spatial influence.

The options recommended above and listed in Appendix B were based in part on examination of two sets of trial simulations for January 2002 and June 2004. For each of these periods

[10] The SST dataset is described at http://dss.ucar.edu/datasets/ds277.7

CALMET was applied according to methods described above with the only difference being in the data used for the surface temperature over land, for air temperature and air-sea temperature difference over the ocean.

Figure 7, Figure 8, and Figure 9 show predicted surface temperatures for January 10, 2002 (0100 AST), June 15, 2004, (1600 AST), and June 16, 2004 (0000 AST). These hours and days were picked at random but are typical of other periods examined by Geomatrix. The interpolated surface temperature fields over land are strictly based on the distance of the grid point from each of the stations. Since there are no observations in the mountains, this technique does not indicate that temperatures are might be colder at such elevations. The MM5 predictions in these figures clearly show expected temperature variations with elevation. Temperature affects the nitrate-nitric acid equilibrium in the chemistry algorithms included in CALPUFF. The nitrate aerosol can be an important component of the CALPUFF predicted changes to extinction.

Although less varied than over land, temperatures in coastal waters differ from those observed farther out in the ocean. As shown in Figure 7 to Figure 9, MM5 and the interpolated buoy observations differ in their characterization of Cook Inlet and other coastal areas. As mentioned above, the MM5 SSTs are passed to CALMET from a database with mesh size of 14-by-28 km and importantly includes data points within Cook Inlet.

CALMET parameterization of the over-water boundary layer is sensitive to the air-sea temperature difference. The extrapolation of the buoy data from Prince William Sound or the open ocean to Cook Inlet does not provide a good basis of characterizing surface energy fluxes. Figure 10 shows an example of the Pasquill stability class distribution predicted for June 15, 2004 (1600). The MM5 simulations account for horizontal changes in temperature caused by the land/ocean interface and predict when warm air is advected over cold water, stable conditions are present (Pasquill stability class 6) in Cook Inlet. However, the three buoys in Prince William Sound during this hour observe a negative air-sea temperature difference (unstable) that is extrapolated to all ocean areas including Cook Inlet. The conditions in Prince William Sound are different than Cook Inlet during this hour. Note, MM5 also predicts an unstable surface layer in most portions of Prince William Sound.

TABLES

TABLE 1

SURFACE METEOROLOGICAL STATIONS

BART CALMET Protocol
Alaska

Site	USAF ID	Lat (ºN)	Lon (ºW)	Elev. (ft)	2002 Obs. (%)	2003 Obs. (%)	2004 Obs. (%)	Name
PAAQ	702740	61.60	149.08	240	98.3	97.7	98.7	Palmer
PABI	702670	64.00	145.73	1274	98.8	98.9	98.0	Big Delta/Delta Junc
PABV	702746	61.42	149.52	95	99.7	99.4	92.8	Birchwood
PACV	702960	60.50	145.50	42	99.5	99.2	99.3	Cordova
PAED	702720	61.25	149.80	193	96.5	95.5	96.4	Elmendorf Afb
PAEN	702590	60.57	151.25	95	98.7	99.3	99.2	Kenai
PAFA	702610	64.82	147.87	454	99.4	99.1	99.4	Fairbanks
PAFK	999999	62.54	153.62	1053	33.7	32.1	24.3	Farewell Lake
PAGK	702710	62.15	145.45	1579	99.4	99.1	98.9	Gulkana (Amos)
PAHO	703410	59.63	151.50	73	99.4	99.2	99.2	Homer
PAIL	703400	59.75	154.92	161	99.4	98.5	98.9	Iliamna (Amos)
PAIN	26489	63.73	148.91	1730	98.6	96.1	99.0	Mckinley Park Obs
PALH	702725	61.18	149.97	72	98.1	98.2	97.0	Lake_Hood_Seaplane
PAMC	702310	62.96	155.61	338	96.7	98.7	98.3	Mcgrath
PAMD	703430	59.43	146.33	46	99.4	99.0	96.7	Middleton (Amos)
PAMH	702460	63.88	152.28	702	94.5	96.8	85.8	Minchumina
PAMR	26409	61.22	149.83	135	99.2	99.0	98.1	Merrill Fld Aprt
PANC	702730	61.17	150.03	132	99.4	99.2	99.3	Anchorage
PANN	702600	64.55	149.08	367	86.9	87.5	98.7	Nenana (Amos)
PASO	999999	59.45	151.70	29	99.1	98.8	96.5	Seldovia
PASP	702711	61.82	147.50	2750	39.1	39.1	37.8	Sheep Mountain
PASW	26514	61.97	151.20	157	34.3	40.6	42.8	Skwentna
PASX	702595	60.48	151.03	108	99.8	99.3	97.7	Soldotna
PATK	702510	62.30	150.10	356	98.0	97.9	97.9	Talkeetna Airport
PATO	999999	60.79	148.83	95	89.0	98.6	96.3	Portage Glacier
PATW	702648	63.40	148.95	2192	35.8	33.4	35.8	Cantwell
PAVD	26442	61.13	146.25	111	98.9	99.0	98.0	Valdez Sawrs
PAVW	702750	61.13	146.35	30	97.5	97.2	97.7	Valdez
PAWD	702770	60.12	149.45	59	93.4	98.8	98.6	Seward
PAWR	26444	60.77	148.68	154	93.5	92.4	91.5	Whittier
PAZK	702715	61.93	147.17	3287	95.6	94.8	99.2	Eureka
PADT	702915	62.70	143.98	2395	36.5	26.9	33.3	Slana Airport
PAEC	702606	62.88	149.83	1250	27.7	24.8	23.2	Chulitna
PAER	999999	61.25	153.82	1175	31.9	33.4	33.6	Merrill Pass West
PAHV	702647	63.88	149.02	1299	31.1	31.6	34.5	Healy_River_Airport
PAHZ	702495	61.98	152.08	1001	34.7	36.5	32.3	Hayes River
PATL	26536	62.90	155.97	964	77.5	89.8	92.2	Tatalina Afs Awos
PAPT	702490	62.10	152.75	1837	35.3	31.4	30.4	Puntilla Lake

TABLE 1 (CONTINUED)

SURFACE METEOROLOGICAL STATIONS
BART CALMET Protocol
Alaska

Site	USAF ID	Lat (ºN)	Lon (ºW)	Elev. (ft)	2002 Obs. (%)	2003 Obs. (%)	2004 Obs. (%)	Name
PAJV	702695	61.72	148.88	869	17.1	15.6	18.1	Sutton
PAUO	702745	61.75	150.05	220	21.5	19.1	16.7	Willow Airport
PASV	702350	61.10	155.57	1587	51.7	86.8	89.4	Sparrevohn Awos
PAFB	702615	64.83	147.62	449	40.2	39.6	42.9	Wainwright_Aaf
PAEI	702650	64.65	147.07	547	68.5	69.1	68.9	Eielson Afb
DENA	999999	63.73	148.96	2169	99.8	99.8	100.0	Denali CASTNET

TABLE 2

HOURLY PRECIPITATION STATIONS
BART CALMET Protocol
Alaska

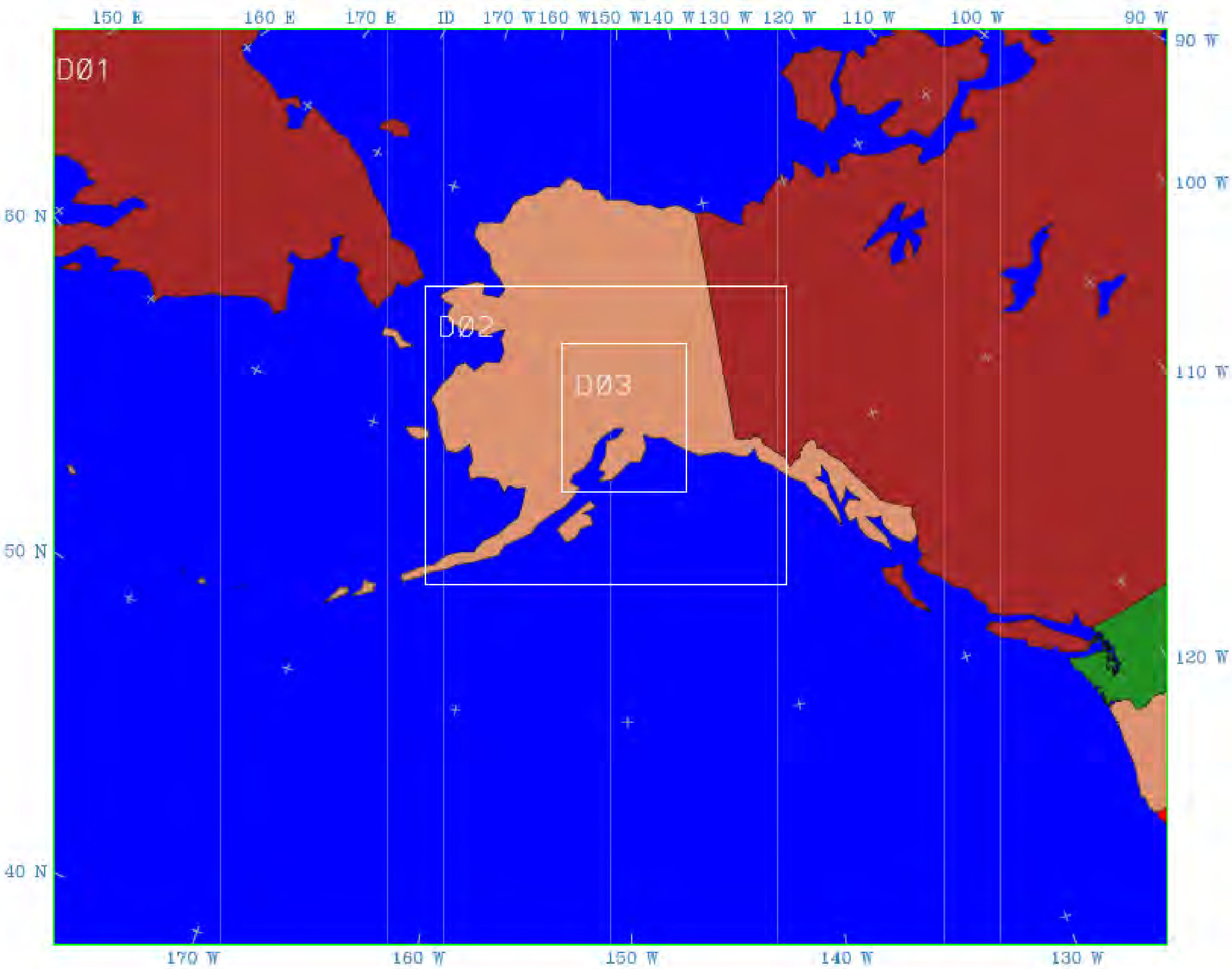
COOP ID	Lat (ºN)	Lon (ºW)	Elev. (ft)	Name
500280	61.17	150.03	132	Anchorage Intl Ap
502968	64.80	147.88	432	Fairbanks Intl Ap
504621	64.92	148.27	1600	Keystone Ridge
505769	62.96	155.61	333	Mcgrath Ap

TABLE 3

BUOY STATIONS
BART CALMET Protocol
Alaska

BUOY ID	Lat (ºN)	Lon (ºW)	Months of Data	Name
46001	56.30	148.02	33	GULF OF AK 88NM South of Kodiak, AK
46060	60.59	146.83	32	West Orca Bay 36NM South Southwest of Valdez, AK
46061	60.22	146.83	36	Seal Rocks 55NM South of Valdez, AK
46066	52.70	154.98	34	S Aleutians 380NM Southwest of Kodiak, AK
46078	56.05	152.45	8	Albatross Banks AK
46079	59.05	152.33	1	Barren Island
46080	58.00	150.00	16	Northwest Gulf 57NM West of Kodiak, AK
46081	60.80	148.28	15	Western Prince William Sound
46082	59.69	143.42	27	Cape Suckling 84NM Southeast of Cordova, AK

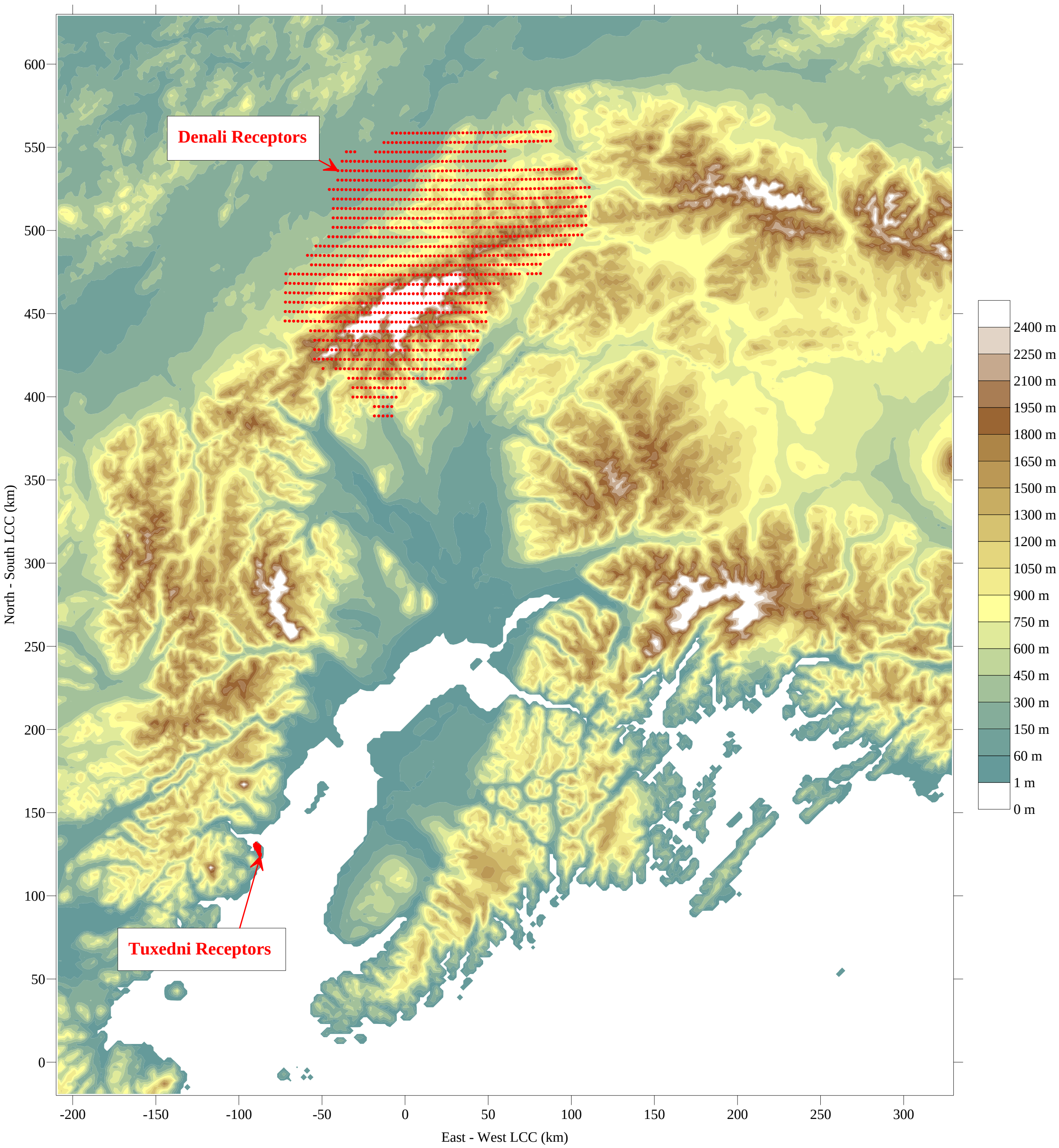
FIGURES



GEOMATRIX

MM5 DOMAINS: D01 – 45KM, D02 – 15KM, D03 – 5KM GRID MESH SIZES
BART CALMET Protocol
Alaska

Project No.
13474.000
Figure
1

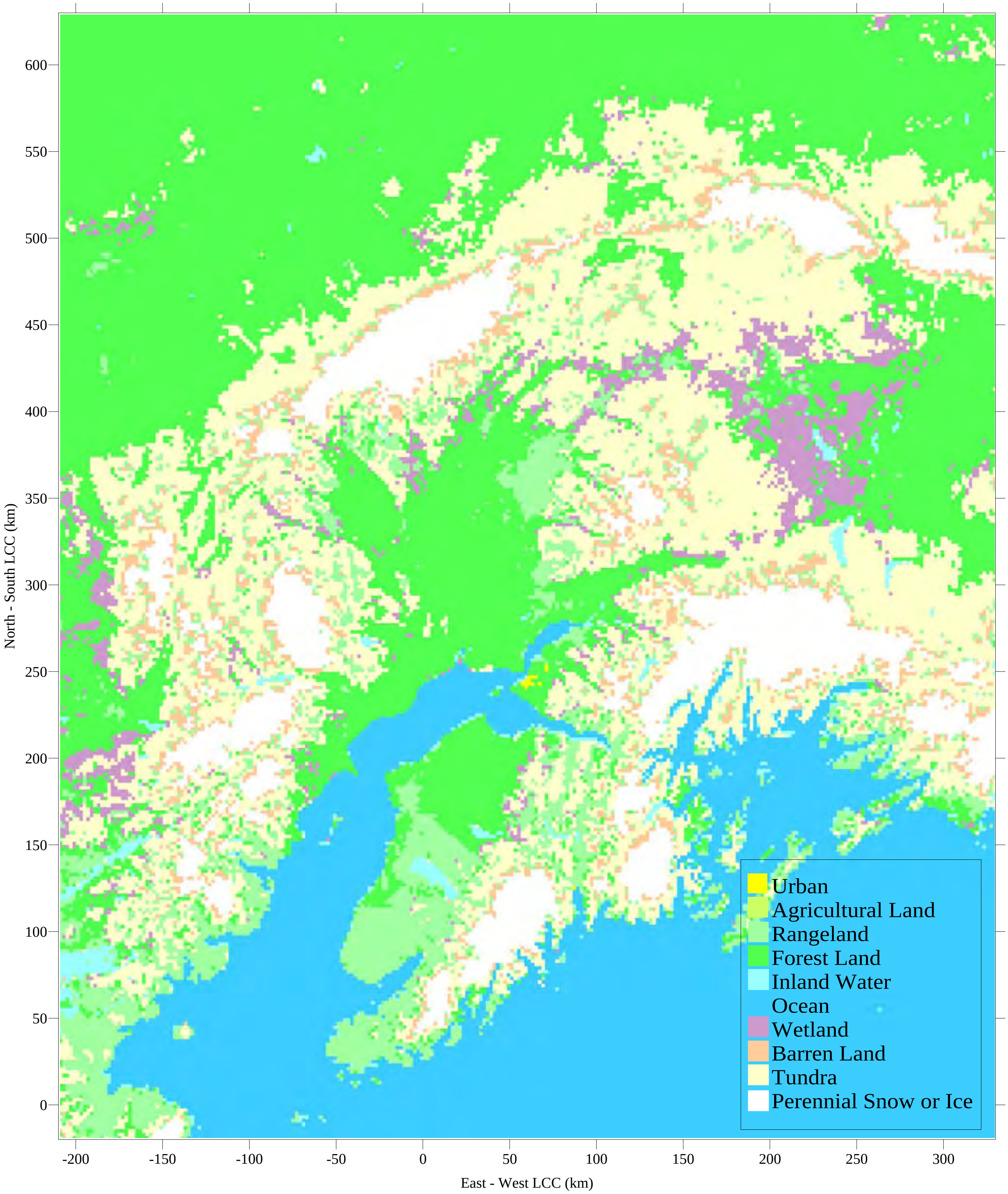


GEOMATRIX

CALMET DOMAIN, CLASS I RECEPTORS, AND 2KM MESH TERRAIN
BART CALMET Protocol
Alaska

Project No.
13474.000

Figure
2

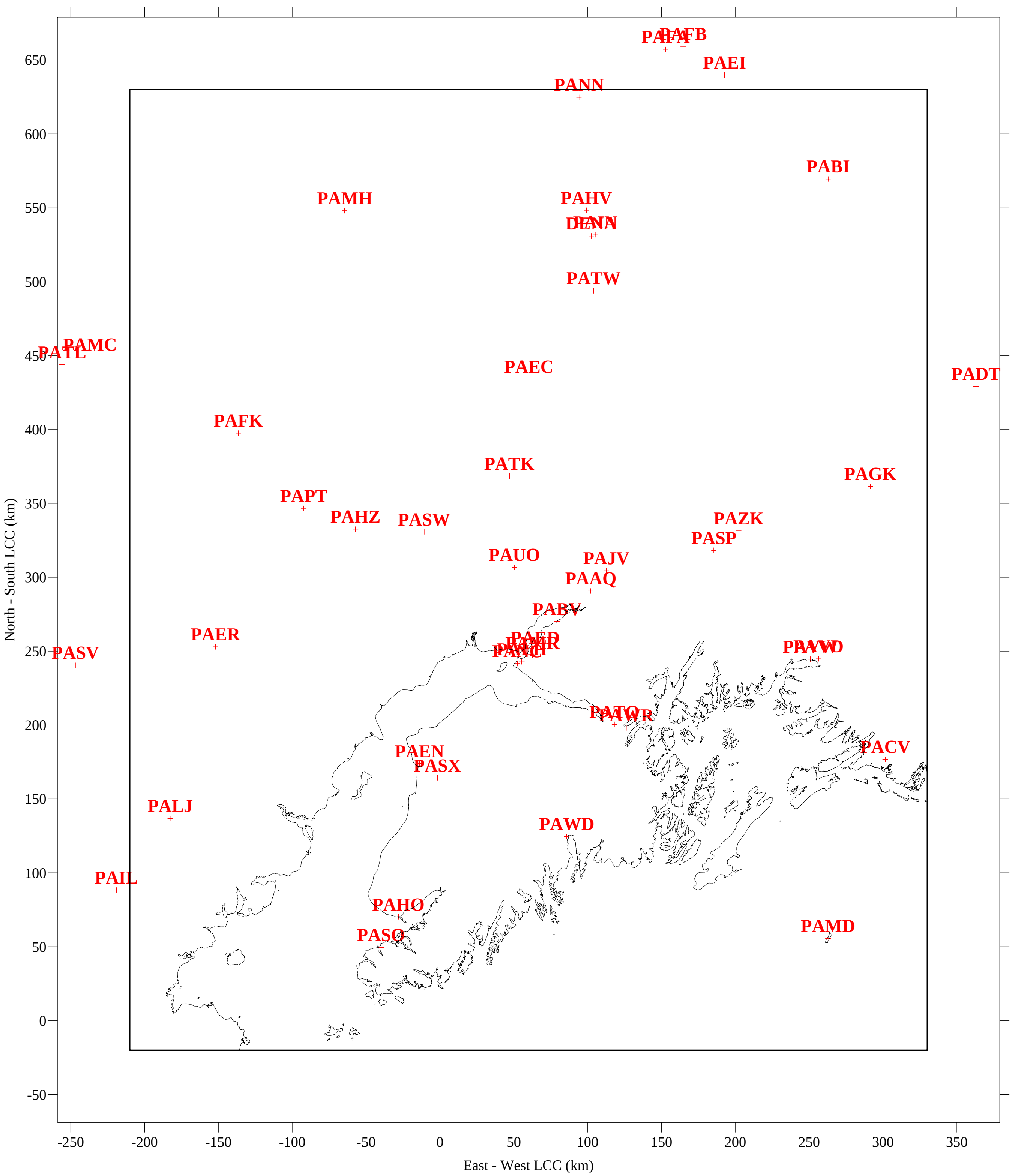


GEOMATRIX

LAND USE
BART CALMET Protocol
Alaska

Project No.
13474.000

Figure
3

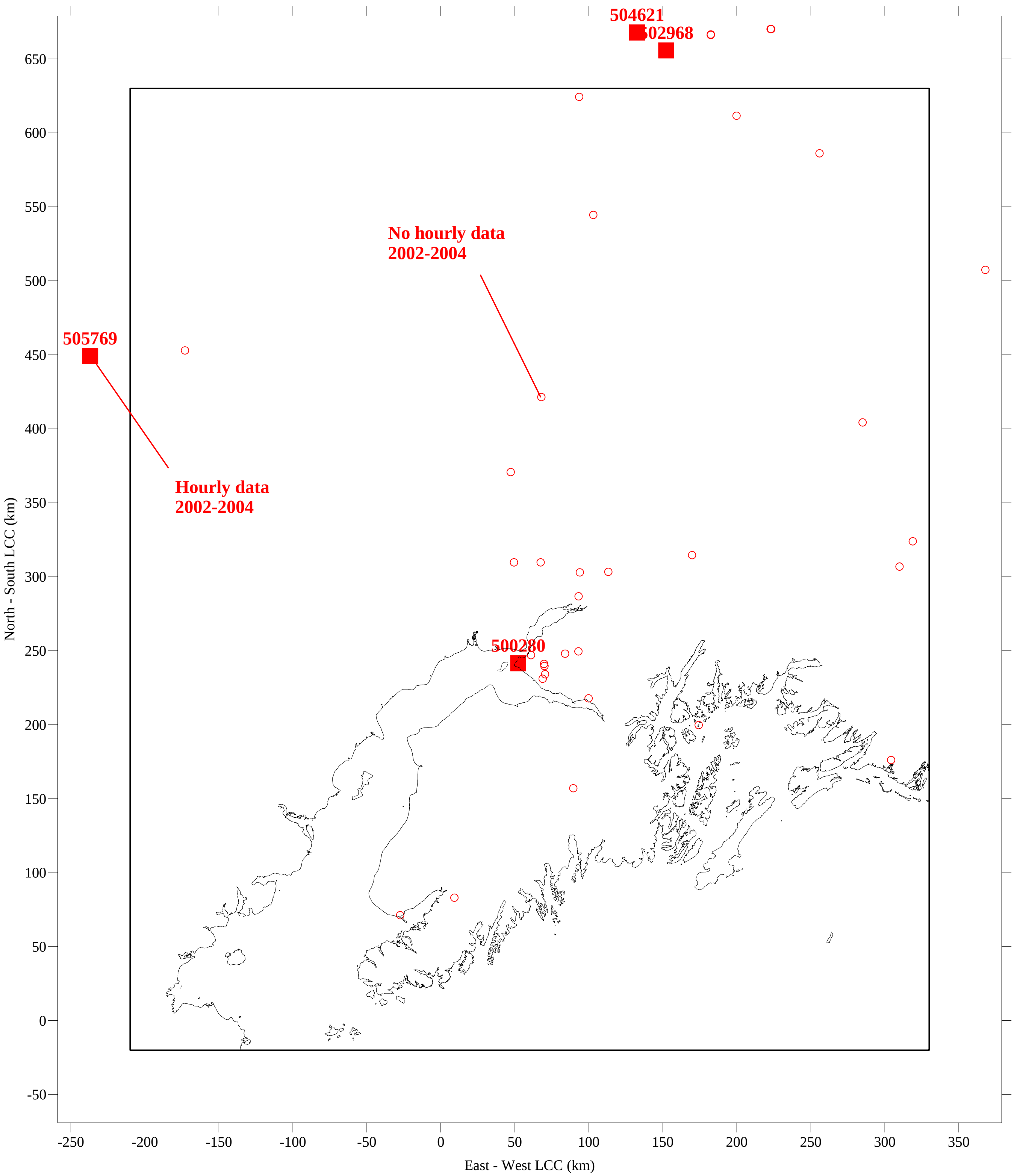


GEOMATRIX

SURFACE WEATHER OBSERVATION SITES
BART CALMET Protocol
Alaska

Project No.
13474.000

Figure
4

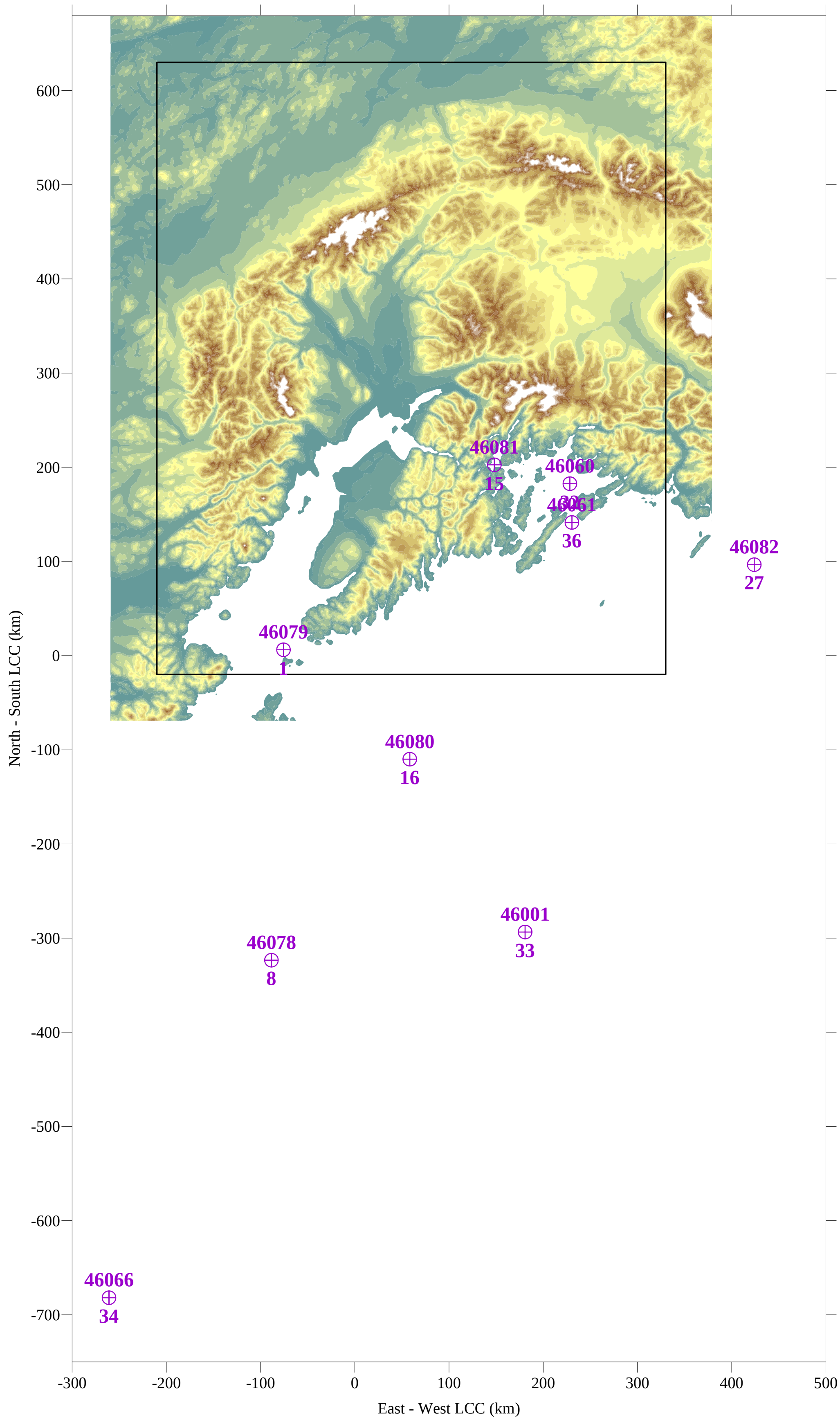


GEOMATRIX

PRECIPITATION OBSERVATION SITES
BART CALMET Protocol
Alaska

Project No.
13474.000

Figure
5

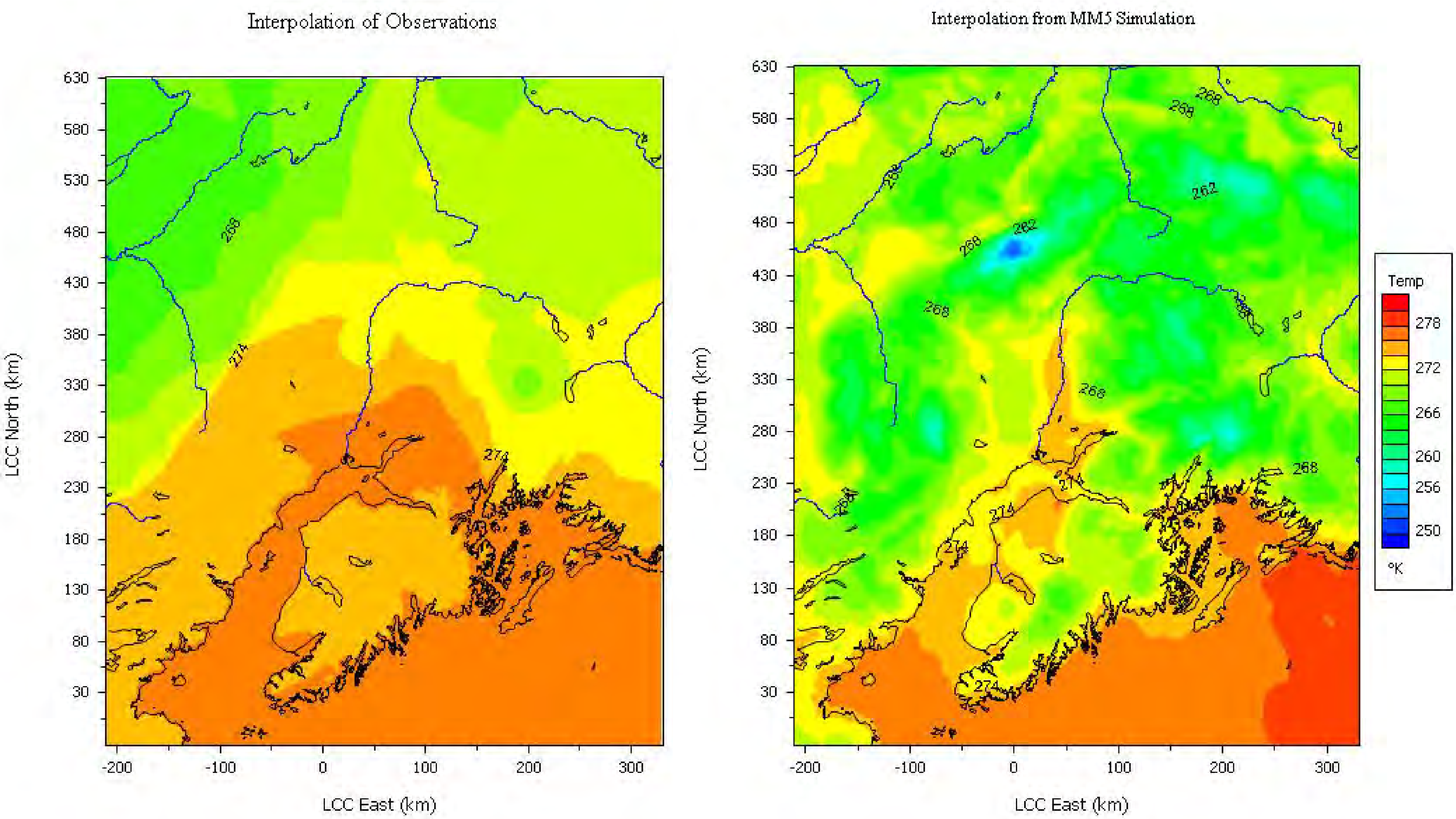


GEOMATRIX

BUOY OBSERVATION SITES AND NUMBER OF MONTHS WITH DATA
BART CALMET Protocol
Alaska

Project No.
13474.000

Figure
6

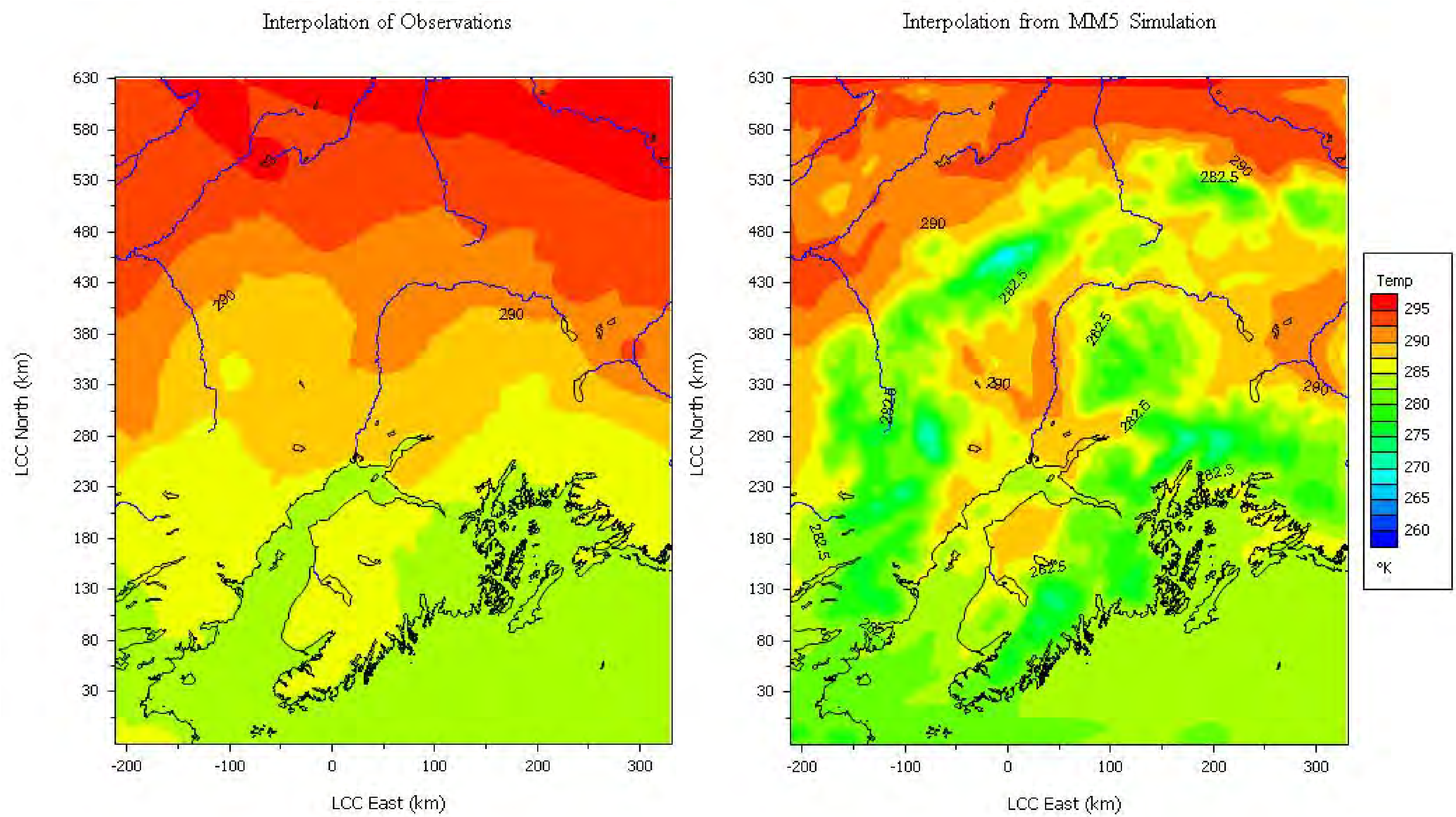


GEOMATRIX

10M TEMPERATURE FOR JANUARY 10, 2002 (0100 AST)
BART CALMET Protocol
Alaska

Project No.
13474.000.0

Figure
7

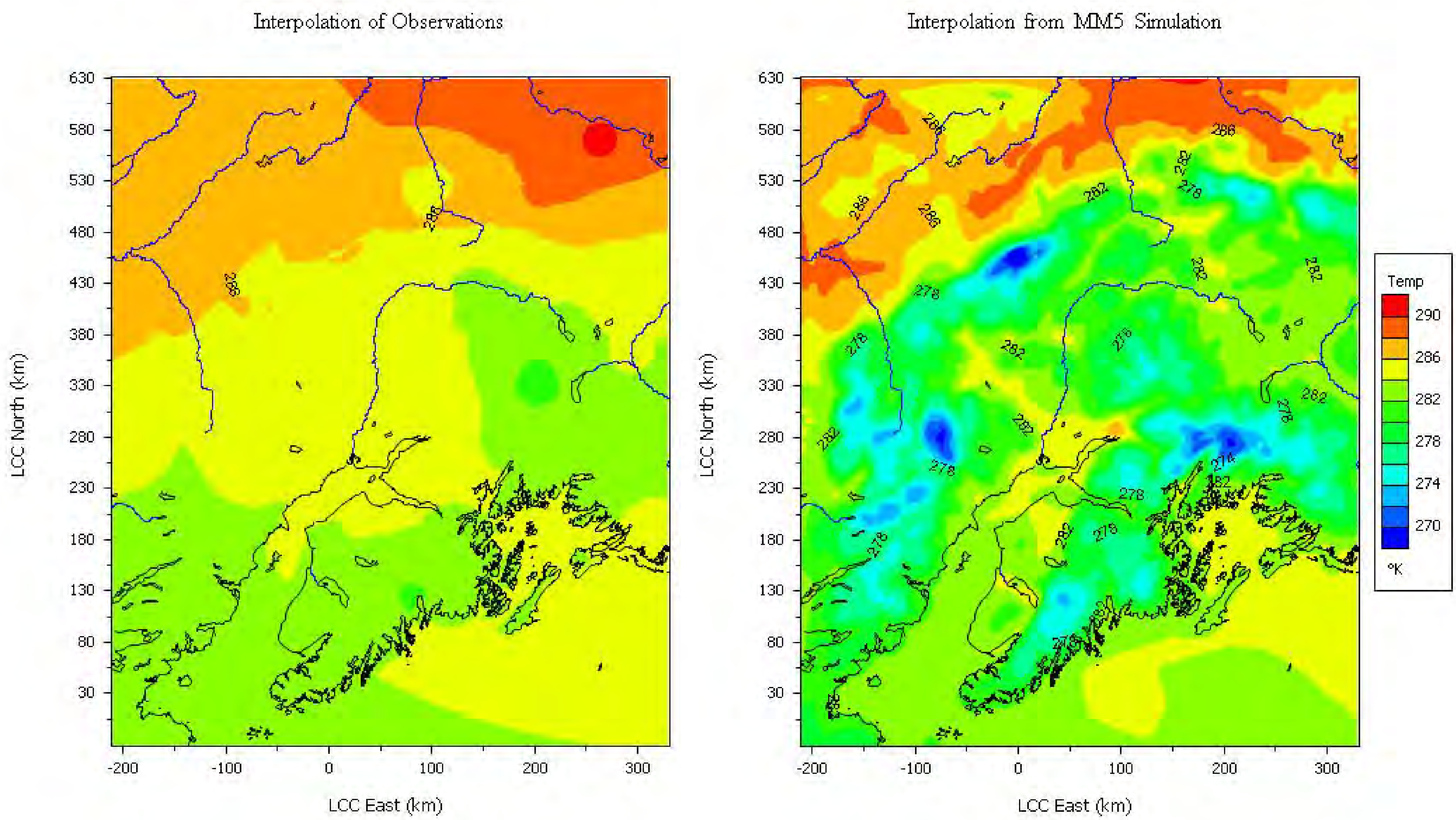


GEOMATRIX

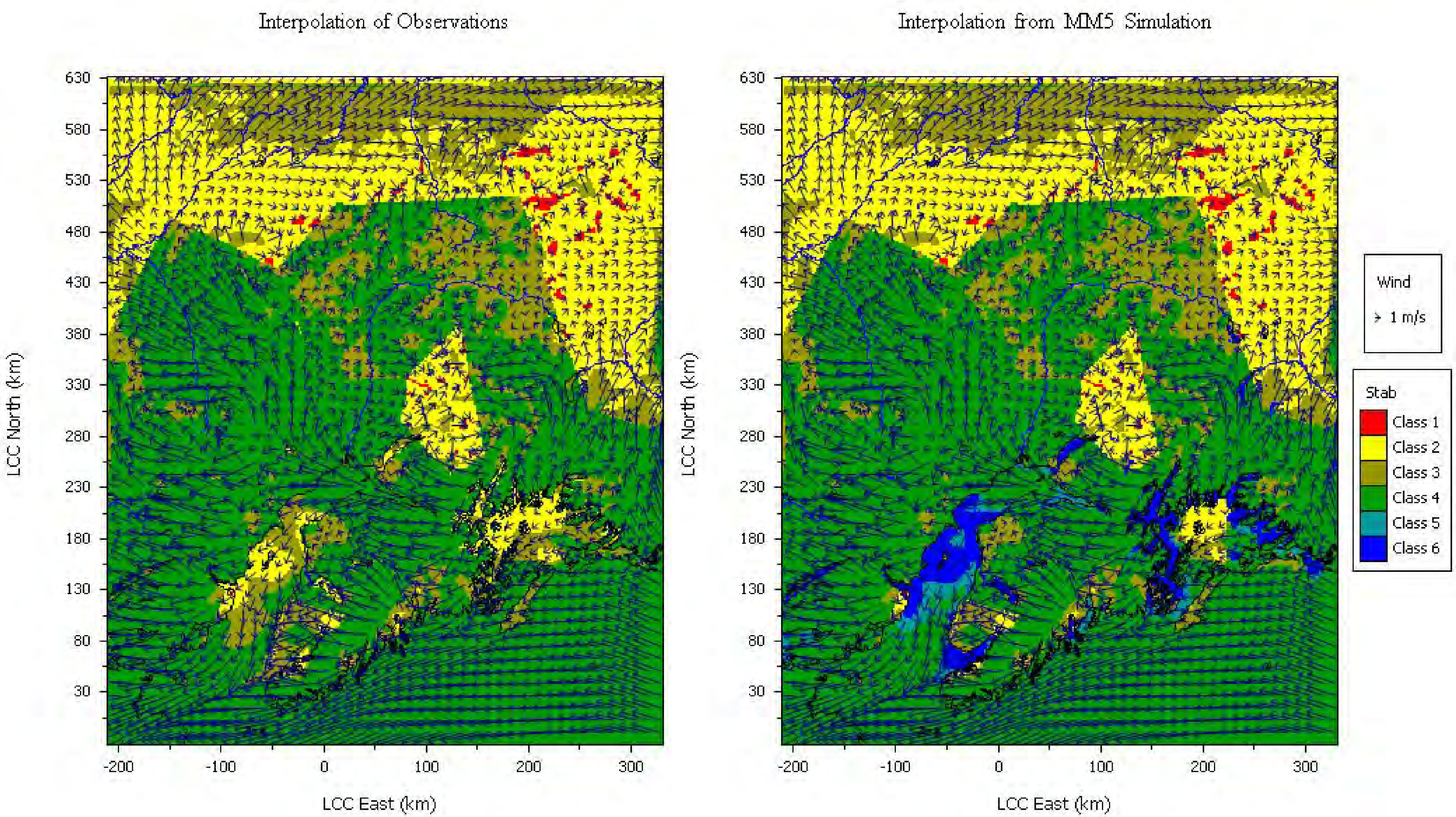
10M TEMPERATURE FOR JUNE 15, 2004 (1600 AST)
BART CALMET Protocol
Alaska

Project No.
13474.000.0

Figure
8



GEOMATRIX	10M TEMPERATURE FOR JUNE 16, 2004 (0000 AST) BART CALMET Protocol Alaska	Project No. 13474.000.0 Figure **9**



GEOMATRIX

STABILTY CLASS AND 10M WINDS (EVERY 6TH SHOWN) FOR JUNE 15, 2004 (1600 AST)
BART CALMET Protocol
Alaska

Project No.
13474.000.0

Figure
10

Appendix A

SAMPLE CALMM5 OUTPUT "3D.DAT" FILE

```
3D.DAT          2.1            Header Structure with Comment Lines
   1
Produced by CALMM5 Version: 2.7     , Level: 061030
  1  1  0  0  0  1
PST   59.0000 -151.0000  90.00   0.00  -210.000   -22.500   5.000 109 130 41
  1  7  3  4  4  1  1  0  1  1  1  1  1  1  1  1  1  1  1  1 25
2002010101  768 109 130  23
   1   1 109 130   1  23 -155.4906 -143.9645  58.6524  64.6442
0.9975
0.9935
0.9875
0.9790
0.9680
0.9550
0.9405
0.9245
0.9070
0.8875
0.8665
0.8435
0.8190
0.7920
0.7635
0.7335
0.7025
0.6705
0.6385
0.6065
0.5745
0.5425
0.5105
   1   1  58.7394 -154.6205  635 21   58.7630 -154.5802  635
   2   1  58.7421 -154.5345  617 21   58.7658 -154.4941  599
   3   1  58.7448 -154.4485  588 21   58.7685 -154.4080  576
   4   1  58.7475 -154.3625  565  8   58.7711 -154.3220  554
   5   1  58.7501 -154.2764  551  8   58.7737 -154.2359  549
   6   1  58.7526 -154.1904  553  8   58.7762 -154.1497  557
   7   1  58.7551 -154.1043  563 21   58.7786 -154.0636  568
   8   1  58.7574 -154.0183  575 21   58.7809 -153.9775  582
   9   1  58.7598 -153.9322  596 21   58.7832 -153.8913  609
  10   1  58.7620 -153.8461  613 21   58.7855 -153.8052  618...
... (truncated) ...
...
 100 130  64.5052 -144.9162  811 15   64.5256 -144.8575  829
 101 130  64.5003 -144.8102  843 15   64.5206 -144.7515  857
 102 130  64.4954 -144.7044  868 15   64.5156 -144.6456  879
 103 130  64.4903 -144.5985  886 15   64.5105 -144.5397  893
 104 130  64.4851 -144.4928  902 15   64.5053 -144.4338  912
 105 130  64.4799 -144.3870  923 15   64.5000 -144.3280  934
 106 130  64.4746 -144.2813  949 15   64.4946 -144.2223  965
 107 130  64.4692 -144.1757  980 15   64.4892 -144.1165  995
 108 130  64.4637 -144.0701 1016 15   64.4836 -144.0109 1037
 109 130  64.4581 -143.9645 1037 15   64.4781 -143.9052 1037
2002010101  1  1  996.1 0.11 1     0.0   315.7   273.4    4.15    56.6
6.5   275.9
 919   654 273.2  57  8.0  0.02 99 4.14
```

```
 915   684 273.1  59  9.9  0.02100 4.14
 910   729 272.9  61 12.0  0.03100 4.13
 903   794 272.7  64 14.2  0.03100 4.11
 893   878 272.5  69 16.6  0.03100 4.09
 882   979 272.3  76 19.1  0.04100 4.09
 870  1092 272.2  85 20.8  0.04100 4.11
 856  1219 272.1  89 18.9  0.03100 4.14
 841  1359 271.5  91 17.0  0.02100 4.03
 824  1518 270.8  92 16.5  0.01100 3.91
 806  1692 270.2  95 16.3 -0.01100 3.81
 787  1887 269.6  98 16.4 -0.02100 3.74
 766  2098 268.8 101 16.9 -0.03100 3.59
 743  2337 267.6 103 17.4 -0.04 99 3.37
 719  2596 266.3 105 18.0 -0.05 98 3.12
 693  2876 264.9 107 18.5 -0.05 96 2.83
 667  3175 263.4 109 19.0 -0.06 94 2.56
 640  3494 261.8 111 19.4 -0.05 92 2.29
 613  3825 260.0 113 19.8 -0.05 89 2.03
 586  4168 258.1 115 20.5 -0.04 87 1.77
 559  4524 256.0 116 21.5 -0.03 85 1.52
 532  4895 253.7 118 22.8 -0.02 83 1.28
 505  5282 251.1 118 24.1 -0.01 81 1.05
2002010101  2  1  996.2 0.11 1     0.0   315.8   273.4    4.15    56.4
6.3   275.9
 921   636 273.2  56  7.5  0.03100 4.15
 917   666 273.1  58  9.4  0.03100 4.16
 912   711 273.0  60 11.4  0.04100 4.14
 905   776 272.8  64 13.5  0.04100 4.12
 895   860 272.6  68 16.1  0.05100 4.10
 884   961 272.4  76 18.6  0.05100 4.10
 872  1074 272.2  84 20.4  0.05100 4.12
 858  1201 272.1  89 18.5  0.05100 4.15
 843  1341 271.5  90 16.7  0.03100 4.04
 826  1501 270.9  92 16.1  0.02100 3.92
 808  1675 270.2  95 16.0  0.01100 3.82
 789  1869 269.7  98 16.1  0.00100 3.75
 768  2081 268.8 100 16.6 -0.01100 3.61
 745  2320 267.7 102 17.1 -0.02100 3.40
 721  2579 266.4 104 17.8 -0.03 99 3.14
 695  2860 265.0 106 18.4 -0.04 97 2.86
 669  3159 263.5 108 18.9 -0.04 94 2.58
 641  3478 261.8 110 19.4 -0.04 92 2.31
 614  3809 260.1 113 19.8 -0.04 90 2.04
 587  4152 258.2 114 20.5 -0.04 88 1.79
 560  4509 256.1 116 21.5 -0.03 86 1.54
 533  4880 253.8 117 22.8 -0.02 83 1.29
 506  5267 251.2 118 24.1 -0.01 81 1.06
2002010101  3  1  996.3 0.11 1     0.0   316.1   273.4    4.16    56.4
5.9   275.9
 924   607 273.3  56  7.0  0.04100 4.17
 921   637 273.3  59  8.9  0.04100 4.18
 916   682 273.1  61 10.9  0.05100 4.17
 908   747 272.9  65 12.9  0.06100 4.14
 899   831 272.7  69 15.7  0.07100 4.13
 887   932 272.6  76 18.2  0.07100 4.13
 875  1045 272.4  85 20.1  0.07100 4.13
```

```
 861  1172 272.2  89 18.1  0.06100 4.16
 846  1313 271.7  90 16.4  0.05100 4.06
 829  1472 271.0  92 15.8  0.04100 3.94
 811  1646 270.3  95 15.6  0.03100 3.84
 792  1841 269.8  98 15.7  0.02100 3.78
 771  2053 269.0 100 16.2  0.01100 3.64
 747  2292 267.8 102 16.8  0.00100 3.44
 723  2552 266.5 104 17.5 -0.01100 3.19
 698  2832 265.1 106 18.2 -0.02 98 2.91
 671  3132 263.6 108 18.8 -0.02 96 2.63
 644  3451 261.9 110 19.4 -0.03 93 2.35
 617  3783 260.2 112 19.9 -0.03 91 2.08
 589  4126 258.3 114 20.5 -0.02 89 1.82
 562  4483 256.3 115 21.5 -0.02 86 1.57
 535  4855 253.9 117 22.8 -0.02 84 1.32
 507  5242 251.4 118 24.1 -0.01 82 1.08

... (truncated) ...
```

Appendix B

DETAILED LIST OF PROPOSED CALMET INPUT VARIABLES AND COMPARISON TO REGION 10 RECOMMEDNDATIONS FOR WASHINGTON, OREGON, AND IDAHO

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
0 - Input and output file names	a	GEODAT	Input filename of geophysical data	GEO.DAT	User defined	geo.2km.dat
		SRFDAT	Input filename of hourly meteorological data	SURF.DAT	User defined	bartsfc.0204.dat
		CLDDAT	Input filename of gridded cloud data	CLOUD.DAT		
		PRCDAT	Input filename of hourly precipitation data	PRECIP.DAT	User defined	**Use MM5 Prec**.
		WTDAT	Input filename of gridded fields of terrain weighting factors	WT.DAT		
		METLST	Output filename of list file	CALMET.LST	User defined	Calmet.2002.01.out
		METDAT	Output filename of generated gridded met fields	CALMET.DAT	User defined	Calmet.2002.01.dat
		PACDAT	Output filename of generated gridded met files (MESEOPUFF II)	PACOUT.DAT		
		LCFILES	Convert names to upper or lower case	User defined	T	T
		NUSTA	Number of upper air stations	User defined	0	0
		NOWSTA	Number of over water met stations	User defined	User defined	9
		NM3D	Number of MM4/MM5/3D.DAT files	User defined	1	1
		NIGF	Number of coarse grid CALMET fields as initial guess fields	User defined	0	0
	b	UPDAT	Input filenames of upper air data	UPn.DAT (n=1,2,3...)		
	c	SEADAT	Input filename of over water stations	SEAn.DAT (n=1,2,3;..)	User defined	Buoy/46001-0204.dat etc
	d	M3DDAT	Input filename of MM4/MM5/3D.DAT	MM51.DAT	User defined	2002.01.5km.m3d
	e	IGFDAT	Input filename of IGF-CALMET files	IGFn.DAT (n=1,2,3...)		
	f	DIADAT	Input filename of preprocessed sfc/UA data	DIAG.DAT		
		PRGDAT	Input filename of prognostic gridded wind fields	PROG.DAT		
		TSTPRT	Output filename of intermediate winds, and misc...etc	TEST.PRT		

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
		TSTOUT	Output filename of final wind fields	TEST.OUT		
		TSTKIN	Output filename of wind fields after kinematic winds	TEST.KIN		
		TSTFRD	Output filename of winds after Froude Number effects	TEST.FRD		
		TSTSLP	Output filename winds after slope effects	TEST.SLP		
		DCSTGD	Output filename of distance land internal variables	DCST.GRD		
1 - General run and control parameters		IBYR	Beginning year	User defined	User defined	2002
		IBMO	Beginning month	User defined	User defined	01
		IBDY	Beginning day	User defined	User defined	01
		IBHR	Beginning hour	User defined	User defined	01
		IEYR	Ending year	User defined	User defined	
		IEMO	Ending month	User defined	User defined	
		IEDY	Ending day	User defined	User defined	
		IEHR	Ending hour	User defined	User defined	
		IBTZ	Base time zone	User defined	8	9
		IRLG	Length of run (hours)	User defined	User defined	744
		IRTYPE	Output type to create	1	1	1
		LCALGRD	Require fields for CALGRID	T	T	T
		ITEST	Flag to stop run after setup phase	2	2	2
		MREG	Conformity to regulatory values (see footnote)	User defined	1	1
2 - Map projection and grid control parameters		PMAP	Map projection	UTM	LCC	LCC
		FEAST	False Easting at projection origin (km)	0.0	0.0	0.0
		FNORTH	False northing at projection origin (km)	0.0	0.0	0.0
		IUTMZN	UTM zone	User defined	-1	-1

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
		UTMHEM	Hemisphere of UTM projection	N	N	N
		RLAT0	Latitude of projection origin (decimal degrees - N)	User defined	49	**59**
		RLON0	Longitude of projection origin (decimal degrees - W)	User defined	121	**151**
		XLAT1	Matching latitude for projection (decimal degrees - N)	User defined	30	30
		XLAT2	Matching latitude of projection (decimal degrees - N)	User defined	60	60
		Datum	Datum-region of output coordinates	WGS-84	NWS-84	NWS-84
		NX	Number of east to west or X grid cells	User defined	373	**270**
		NY	Number of north to south or Y grid cells	User defined	316	**325**
		DGRIDKM	Grid spacing in kilometers (km)	User defined	4	**2**
		XORIGKM	Southwest corner of grid cell (1,1), X-coordinate (km)	User defined	-572	**-210**
		YORIGKM	Southwest corner of grid cell (1,1), Y-coordinate (km)	User defined	-956	**-20**
		NZ	Number of vertical layers	User defined	10	10
		ZFACE	Cell face heights in arbitrary vertical grid (ZFACE (NZ+1)) (m)	User defined	0,20,40,65,120,200, 400,700,1200,2200, 4000	0,20,40,65,120,200, 400,700,1200,2200, 4000
3 - Output options		LSAVE	Save met fields in unformatted file	T	T	T
		IFORMO	Type of unformatted output file	1	1	1
		LPRINT	Print met fields	F	F	F
		IPRINF	Print interval in hours	1	12	12
		IUVOUT	Layers of U, V wind components to print (IUVOUT (NZ))	NZ*0	1,9*0	1,9*0
		IWOUT	Levels of W wind component to print (IWOUT (NZ))	NZ*0	10*0	10*0
		ITOUT	Levels of 3-D temps to print (ITOUT (NZ)	NZ*0	1,9*0	1,9*0
		STABILITY	Print PGT Stability	0	1	1
		USTAR	Print friction velocity	0	0	0

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
		MONIN	Print Monin-Obukhov	0	0	0
		MIXHT	Print mixing height	0	1	1
		WSTAR	Print convective velocity scale	0	0	0
		PRECIP	Print precipitation rate	0	1	1
		SENSHEAT	Print sensible heat flux	0	0	0
		CONVZI	Print convective mixing height (Zic)	0	0	0
		LDB	Print met data and internal variables)	F	F	F
		NN1	Test and debug print options: first time step	1	1	1
		NN2	Test and debug print options: last time step	1	1	1
		LDBCST	Test and debug print options: distance to land internal variables	F	F	F
		IOUTD	Test and debug print options: control variables for writing winds	0	0	0
		NZPRN2	Test and debug print options: number of levels starting at sfc	1	1	1
		IPR0	Test and debug print options: interpolated winds	0	0	0
		IPR1	Test and debug print options: terrain adjusted surface wind	0	0	0
		IPR2	Test and debug print options: smoothed wind and diverge fields	0	0	0
		IPR3	Test and debug print options: final wind speed and direction	0	0	0
		IPR4	Test and debug print options: final divergence	0	0	0
		IPR5	Test and debug print options: winds after Kinematic effects	0	0	0
		IPR6	Test and debug print options: winds after Froude No. adjustment	0	0	0
		IPR7	Test and debug print options: winds after slope flow	0	0	0
		IPR8	Test and debug print options: final winds	0	0	0

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
4 - Meteorological data options		NOOBS	No observation mode	0	1	1
		NSSTA	Number of surface stations	User defined	User defined	45
		NPSTA	Number of precipitation stations	User defined	User defined	**-1 (use MM5 prec.)**
		ICLOUD	Gridded cloud fields	0	0	0
		IFORMS	Surface met data file format	2	2	2
		IFORMP	Precipitation data file format	2	2	2
		IFORMC	Cloud data format	2	2	2
5 - Wind field options and parameters		IWFCOD	Wind model options	1	1	1
		IFRADJ	Compute Froude number adjustment effects	1	1	1
		IKINE	Compute Kinematic effects	0	0	0
		IOBR	Use O'Brien procedures for adjust vertical velocity	0	0	0
		ISLOPE	Compute slope effects	1	1	1
		IEXTRP	Extrapolate sfc wind obs to upper levels	-4	-4	-4
		ICALM	Extrapolate sfc winds even if calm	0	0	0
		BIAS	Surface/upper weighting factors (BIAS (NZ))	NZ*0	10*0	10*0
		RMIN2	Minimum distance for extrapolation of winds	4	4	4
		IPROG	Use prognostic model winds as input to diagnostic wind model	0	14	14
		ISTEPPG	Timestep (hours) of prognostic model data	1	1	1
		IGFMET	Use coarse CALMET fields as initial guess	0	0	0
		LVARY	Use varying radius of influence	F	F	F
		RMAX1	Maximum radius of influence in surface layer (km)	User defined	36	**15 (3xMM5 mesh)**
		RAMX2	Maximum radius of influence over land aloft (km)	User defined	36	**15 (3xMM5 mesh)**
		RMAX3	Maximum radius of influence over water (km)	User defined	50	**20 (4xMM5 mesh)**

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
		RMIN	Minimum radius of influence in wind field interpolation (km)	0.1	0.1	0.1
		TERRAD	Radius of influence of terrain features (km)	User defined	8	**5 (MM5 mesh)**
		R1	Relative weight at surface of 1st guess fields and obs (km)	User defined	2	**2.5 (.5xMM5 mesh)**
		R2	Relative weight aloft of 1st guess fields and obs (km)	User defined	2	**2.5 (.5xMM5 mesh)**
		RPROG	Weighting factors of prognostic wind field data (km)	User defined	0	0
		DIVLIM	Maximum acceptable divergence	0.000005	0.000005	0.000005
		NITER	Maximum number of iterations in divergence minimum	50	50	50
		NSMTH	Number of passes in smoothing (NSMITH (NZ))	2, (nxnz-1)*4	1,2,2,3,3,4,4,4,4,4	1,2,2,3,3,4,4,4,4,4
		NINTR2	Maximum number of stations for interpolation (NINTR2(NZ))	99	10*99	10*99
		CRITFN	Critical Froude Number	1	1	1
		ALPHA	Empirical factor controlling influence of kinematic effects	0.1	0.1	0.1
		FEXTR2	Multiplicative scaling factor for extrap of sfc obs to upper layers (FEXTRS(NX))	NZ*0.0	10*0	10*0
		NBAR	Number of barriers to interpolation of wind fields	0	0	
		KBAR	Level (1 to NZ) up to which barriers apply	NZ	10	10
		XBBAR (NBAR>0)	X coordinate of beginning of each barrier (km)	User defined	0	0
		YBBAR (NBAR>0)	Y coordinate of beginning of each barrier (km)	User defined	0	0
		XEBAR (NBAR>0)	X coordinate of ending of each barrier (km)	User defined	0	0
		YEBAR (NBAR>0)	Y coordinate of ending of each barrier (km)	User defined	0	0
		IDIOPT1	Compute surface temperature	0	0	0
		ISURFT b	Sfc met station to use for sfc temp	User defined	Salem, OR	**19 (Anchorage)**
		IDIOPT2	Domain-averaged temp lapse rate	0	0	0
		IUPT (IDIOPT2=0) b	UA station to use for the domain-scale lapse rate	User defined	User defined	1

CALMET 5.8 (070623) Input Variable Selection

Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
		ZUPT (IDIOPT2=0)	Depth through which domain-scale lapse rate is computed (m)	200	200	200
		IDIOPT3	Domain-averaged wind component	0	0	0
		IUPWIND (IDIOPT3=0)	UA station to use for domain-scale winds	-1	-1	-1
		ZUPWIND (IDIOPT3=0)	Bottom and top of layer thru which domain winds computed (m)	1., 1000	1.,1000	1.,1000
		IDIOPT4	Read observed surface wind components	0	0	0
		IDIOPT5	Read observed upper wind components	0	0	0
		LLBREZE	Use lake breeze module	F	F	F
		NBOX	Number of lake breeze regions	User defined	0	0
		XG1	X grid line 1 defining the region of interest	User defined	0	0
		XG2	X grid line 2 defining the region of interest	User defined	0	0
		YG1	Y grid line 1 defining the region of interest	User defined	0	0
		YG2	Y grid line 2 defining the region of interest	User defined	0	0
		XBCST	X point defining the coastline (km)	User defined	0	0
		YBCST	Y point defining the coastline (km)	User defined	0	0
		XECST	X point defining the coastline (km)	User defined	0	0
		YECST	Y point defining the coastline (km)	User defined	0	0
		NLB	Number of stations in the region (sfc + upper air)	User defined	0	0
		METBXID	Station ID’s in the region (METBXID (NLB))	User defined	0	0
6 - Mixing height, temperature and precipitation parameters		CONSTB	Mix ht constant: neutral, mechanical equation	1.41	1.41	1.41
		CONSTE	Mix ht constant: convective equation	0.15	0.15	0.15
		CONSTN	Mix ht constant: stable equation	2400	2400	2400
		CONSTW	Mix ht equation: over water	0.16	0.16	0.16
		FCORIOL	Absolute value of Coriolis parameter	0.0001	0.0001	0.0001

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
		IAVEZI	Spatial averaging of Mix ht: conduct spatial averaging	1	1	1
		MNMDAV	Spatial averaging of Mix ht: Max search radius (# of grid cells)	1	1	1
		HAFANG	Spatial avg'n of Mix ht: 0.5-angle of upwind cone for avg (deg)	30	30	30
		ILEVZI	Spatial averaging of Mix ht: Layer of winds used in upwind	1	1	1
		IMIXH	Zic Mix Ht Options: Method to compute Mix ht	1	-1	-1
		THRESHL	Zic Mix Ht Options: Threshold buoyancy flux reqrd to sustain over land (W/m3)	0.05	0.0	0.0
		THRESHW	Zic Mix Ht Options: Threshold buoyancy flux reqrd sustain over water (W/m3)	0.05	0.05	0.05
		ITWPROG	Overwater temp, air-sea temp, & lapse rates	0	0	**2 (use MM5 sea temp, air-sea temp, and lapse rate)**
		ILUOC3D	Zic Mix Ht Options: Land use category in 3D.DAT	16	16	16
		DPTMIN	Min potential Temp lapse rate in stable layer above Zic (deg-K/m)	0.001	0.001	0.001
		DZZI	Depth of computing capping lapse rate (m)	200	200	200
		ZIMIN	Minimum over land mixing height (m)	50	50	50
		ZIMAX	Maximum over land mixing height (m)	3000	3000	3000
		ZIMINW	Minimum over water mixing height (m)	50	50	50
		ZIMAXW	Maximum over water mixing height (m)	3000	3000	3000
		ICOARE	Over water surface fluxes methods and parameters	10	0	0
		DSELF	Coastal/shallow water length scale (km)	0	0	0
		IWARM	COARE warm layer computation	0	0	0
		ICOOL	COARE cool skin layer computation	0	0	0
		ITPROG	3D temp from obs or from prognostic data	0	1	**2 (use MM5 3D temp)**
		IRAD	Temp interpolation type	1	1	1

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
		TRADKM	Radius of influence of temp interpolation (km)	500	500	500
		NUMTS	Max number of stations to include in interpolation	5	5	5
		IAVET	Conduct spatial averaging of temp	1	1	1
		TGDEFB	Default temp gradient below mix ht over water (deg-K/m)	-0.0098	-0.0098	-0.0098
		TGDEFA	Default temp gradient above mix ht over water (deg-K/m)	-0.0045	-0.0045	-0.0045
		JWAT1	Beginning land use categories for temp interpolation over water	User defined - 999	55	55
		JWAT2	Ending land use categories for temp interpolation over water	User defined - 999	55	55
		NFLAGP	Method of precipitation interpolation	2	2	2
		SIGMAP	Radius of influence for precipitation (km)	100	20	**5 (MM5 mesh)**
		CUTP	Minimum precipitation rate cutoff (mm/hr)	0.01	.01	.01
7 -Surface meteorological station parameters		CSNAM	Station name	User defined	User defined	PAAQ etc
		IDSSTA	Station identification number	User defined	User defined	702740 etc
		XSSTA	X-coordinate (km)	User defined	User defined	102.119 etc
		YSSTA	Y-coordinate (km)	User defined	User defined	290.735 etc
		XSTZ	Time zone	User defined	User defined	9 etc
		ZANEM	Anemometer height (m)	User defined	User defined	10 etc
8- Upper air meteorological station parameters		CUNAM	Station name	User defined		
		IDUSTA	Station identification number	User defined		
		XUSTA	X-coordinate (km)	User defined		
		YUSTA	Y-coordinate (km)	User defined		
		UUTZ	Time zone	User defined		

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	WA, OR, ID PSD	Alaska BART
9 Precipitation station parameters		CPNAM	Station name	User defined	User defined	**Use MM5 Prec**
		IDPSTA	Station identification number	User defined	User defined	**Use MM5 Prec**
		XPSTA	X-coordinate (km)	User defined	User defined	**Use MM5 Prec**
		YPSTA	Y-coordinate (km)	User defined	User defined	**Use MM5 Prec**

Geomatrix

December 17, 2007
Project 13474.000

Alan E Schuler, P.E.
State of Alaska
Department of Environmental Conservation
PO Box 111800
410 Willoughby Ave., Suite 303
Juneau, Alaska 99811-1800

Subject: CALMET Modeling Protocol - Addendum
Alaska CALMET Modeling for BART

Dear Mr. Schuler:

Geomatrix prepared this addendum to the *Alaska CALMET Modeling Protocol* based on discussions during the December 13, 2007 conference call hosted by Alaska Department of Environmental Conservation (ADEC). The original protocol was submitted on behalf of the Alaska BART Coalition to ADEC on September 28, 2007. ADEC provided comments on the protocol in your letter of December 4, 2007.

Please find attached a Revised CALMET Protocol Appendix B that includes our amended proposed settings and options for applying CALMET for Alaska BART simulations. The protocol revisions are those requested by Mr. Tim Allen of the U. S. Fish and Wildlife Service (FWS) and the ADEC during the December 13, 2007 conference call, namely:

- The ITPROG and ITWPROG options were changed so CALMET will use available observations for surface temperature and air-sea temperature difference. These options in the original protocol directed CALMET to obtain these variables from MM5 simulations.

- The NPSTA and SIGMAP options were altered to allow a blending of hourly precipitation observations in the study domain with "pseudo stations" constructed from the MM5 simulations. We obtained hourly precipitation data for Alaska from the National Climatic Data Center and found the eight stations listed in Table1 had at least one day of data during 2002 through 2004. The observations will be combined with simulated hourly precipitation using every other grid point of the MM5 5-km domain. Figure 1 shows the locations of the combined data set.

While we do not agree that these revisions are more scientifically sound than the options in the original protocol, we understand CALMET simulations prepared with the settings in this addendum more closely follow regulatory practices preferred by the FWS and ADEC. We also understand that the amended CALMET protocol and an approved CALPUFF protocol will allow

Alan E Schuler
Alaska Department of Environmental Quality
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members of the Alaska BART Coalition to use the 98th percentile change to the Haze Index as a criterion for BART Exemption simulations.

The prompt agency review of these proposed changes and approval of the amended Alaska CALMET Modeling Protocol is appreciated so that the members of the Alaska BART Coalition can proceed to the modeling analysis and meet the upcoming regulatory deadlines. Please contact me if you have questions regarding the proposed revisions or the Alaska CALMET Modeling Protocol.

Sincerely yours,
GEOMATRIX CONSULTANTS, INC.

Ken Richmond
Senior Air Quality Scientist

Enclosure: Revised CALMET Protocol Appendix B

cc: Mike Harper - Agrium
Brad Thomas – Alyeska Pipeline Service Company
Lena Saville – Anchorage Municipal Light and Power
Marta Czarnezki – ConocoPhillips Alaska, Inc.
Chris Drechsel – Tesoro Alaska Company
Al Trbovich – Hoefler Consulting
Doug Murray – TRC Solutions
Tim Allen – FWS
John Notar – NPS
Tom Turner – ADEC/APP Anchorage
Rebecca Smith, ADEC/APP Juneau

Alan E Schuler
Alaska Department of Environmental Quality
December 17, 2007
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TABLE 1

HOURLY PRECIPITATION STATIONS
BART CALMET Protocol
Alaska

COOP ID	**Lat (ºN)**	**Lon (ºW)**	**Elev. (ft)**	**Name**
500277	61.18	149.97	90	Anchorage Lake Hood Airport
500280	61.17	150.03	132	Anchorage Intl Airport
502965	64.82	147.87	427	Fairbanks Airport #2
502968	64.80	147.88	432	Fairbanks Intl Airport
504621	64.92	148.27	1600	Keystone Ridge
505769	62.96	155.61	333	McGrath Airport
506867	61.60	149.09	230	Palmer Airport
509385	61.65	145.17	1595	Tonsina

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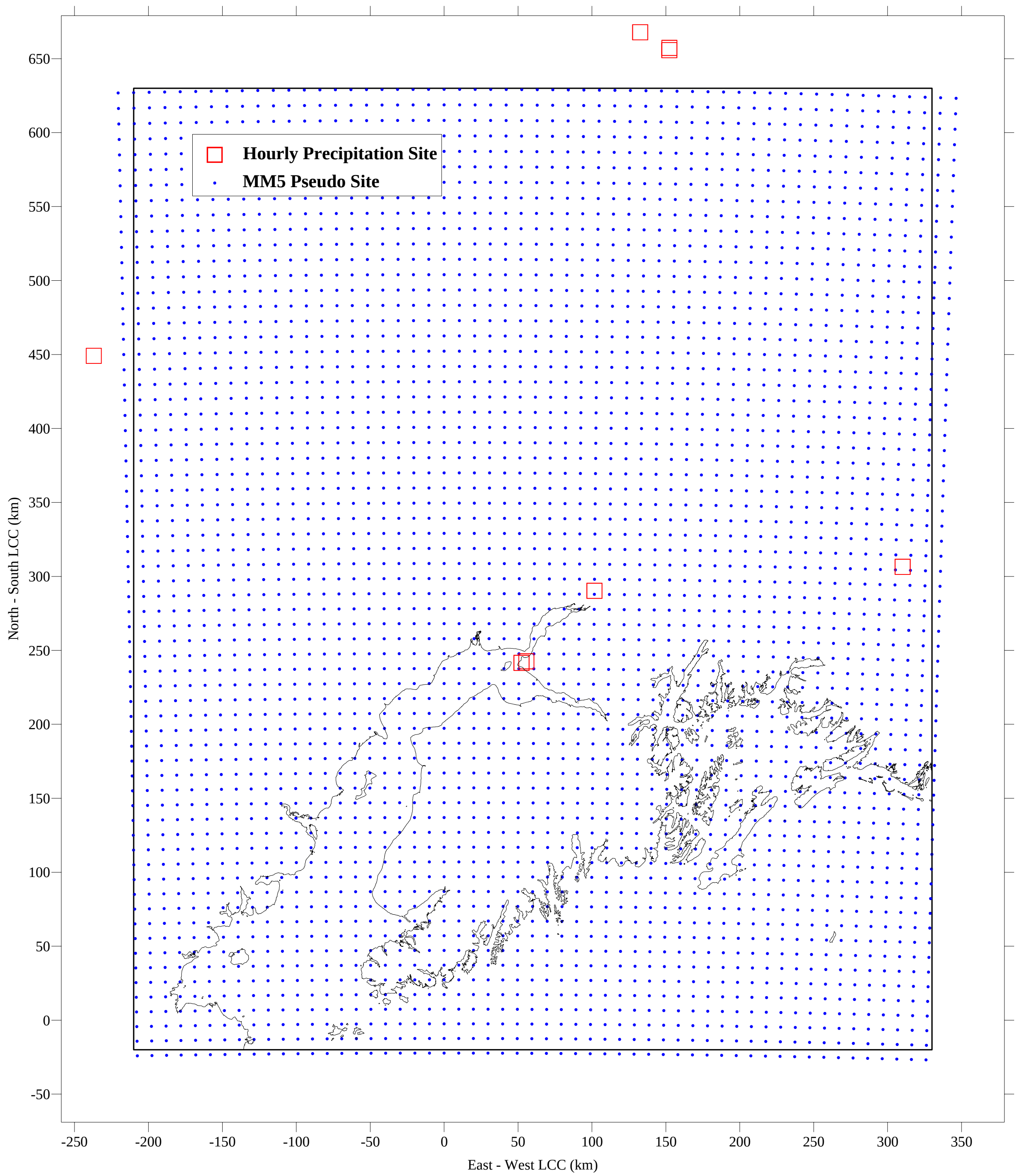

GEOMATRIX	PRECIPITATION SITES AND MM5 PSEUDO STATIONS BART CALMET Protocol Alaska	Project No. 13474.000 Figure 1

Revised CALMET Protocol - Appendix B

DETAILED LIST OF PROPOSED CALMET INPUT VARIABLES

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	Alaska BART
0 - Input and output file names	a	GEODAT	Input filename of geophysical data	GEO.DAT	geo.2km.dat
		SRFDAT	Input filename of hourly meteorological data	SURF.DAT	bartsfc.0204.dat
		CLDDAT	Input filename of gridded cloud data	CLOUD.DAT	
		PRCDAT	Input filename of hourly precipitation data	PRECIP.DAT	precip.0204.dat
		WTDAT	Input filename of gridded fields of terrain weighting factors	WT.DAT	
		METLST	Output filename of list file	CALMET.LST	Calmet.2002.01.out
		METDAT	Output filename of generated gridded met fields	CALMET.DAT	Calmet.2002.01.dat
		PACDAT	Output filename of generated gridded met files (MESEOPUFF II)	PACOUT.DAT	
		LCFILES	Convert names to upper or lower case	User defined	T
		NUSTA	Number of upper air stations	User defined	0
		NOWSTA	Number of over water met stations	User defined	9
		NM3D	Number of MM4/MM5/3D.DAT files	User defined	1
		NIGF	Number of coarse grid CALMET fields as initial guess fields	User defined	0
	b	UPDAT	Input filenames of upper air data	UPn.DAT (n=1,2,3...)	
	c	SEADAT	Input filename of over water stations	SEAn.DAT (n=1,2,3;..)	Buoy/46001-0204.dat etc
	d	M3DDAT	Input filename of MM4/MM5/3D.DAT	MM51.DAT	2002.01.5km.m3d
	e	IGFDAT	Input filename of IGF-CALMET files	IGFn.DAT (n=1,2,3...)	
	f	DIADAT	Input filename of preprocessed sfc/UA data	DIAG.DAT	
		PRGDAT	Input filename of prognostic gridded wind fields	PROG.DAT	
		TSTPRT	Output filename of intermediate winds, and misc...etc	TEST.PRT	

CALMET 5.8 (070623) Input Variable Selection

Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	Alaska BART
		TSTOUT	Output filename of final wind fields	TEST.OUT	
		TSTKIN	Output filename of wind fields after kinematic winds	TEST.KIN	
		TSTFRD	Output filename of winds after Froude Number effects	TEST.FRD	
		TSTSLP	Output filename winds after slope effects	TEST.SLP	
		DCSTGD	Output filename of distance land internal variables	DCST.GRD	
1 - General run and control parameters		IBYR	Beginning year	User defined	2002
		IBMO	Beginning month	User defined	01
		IBDY	Beginning day	User defined	01
		IBHR	Beginning hour	User defined	01
		IEYR	Ending year	User defined	
		IEMO	Ending month	User defined	
		IEDY	Ending day	User defined	
		IEHR	Ending hour	User defined	
		IBTZ	Base time zone	User defined	9
		IRLG	Length of run (hours)	User defined	744
		IRTYPE	Output type to create	1	1
		LCALGRD	Require fields for CALGRID	T	T
		ITEST	Flag to stop run after setup phase	2	2
		MREG	Conformity to regulatory values (see footnote)	User defined	1
2 - Map projection and grid control parameters		PMAP	Map projection	UTM	LCC
		FEAST	False Easting at projection origin (km)	0.0	0.0
		FNORTH	False northing at projection origin (km)	0.0	0.0
		IUTMZN	UTM zone	User defined	-1

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	Alaska BART
		UTMHEM	Hemisphere of UTM projection	N	N
		RLAT0	Latitude of projection origin (decimal degrees - N)	User defined	59
		RLON0	Longitude of projection origin (decimal degrees - W)	User defined	151
		XLAT1	Matching latitude for projection (decimal degrees - N)	User defined	30
		XLAT2	Matching latitude of projection (decimal degrees - N)	User defined	60
		Datum	Datum-region of output coordinates	WGS-84	NWS-84
		NX	Number of east to west or X grid cells	User defined	270
		NY	Number of north to south or Y grid cells	User defined	325
		DGRIDKM	Grid spacing in kilometers (km)	User defined	2
		XORIGKM	Southwest corner of grid cell (1,1), X-coordinate (km)	User defined	-210
		YORIGKM	Southwest corner of grid cell (1,1), Y-coordinate (km)	User defined	-20
		NZ	Number of vertical layers	User defined	10
		ZFACE	Cell face heights in arbitrary vertical grid (ZFACE (NZ+1)) (m)	User defined	0,20,40,65,120,200, 400,700,1200,2200, 4000
3 - Output options		LSAVE	Save met fields in unformatted file	T	T
		IFORMO	Type of unformatted output file	1	1
		LPRINT	Print met fields	F	F
		IPRINF	Print interval in hours	1	12
		IUVOUT	Layers of U, V wind components to print (IUVOUT (NZ))	NZ*0	1,9*0
		IWOUT	Levels of W wind component to print (IWOUT (NZ))	NZ*0	10*0
		ITOUT	Levels of 3-D temps to print (ITOUT (NZ)	NZ*0	1,9*0
		STABILITY	Print PGT Stability	0	1
		USTAR	Print friction velocity	0	0

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	Alaska BART
		MONIN	Print Monin-Obukhov	0	0
		MIXHT	Print mixing height	0	1
		WSTAR	Print convective velocity scale	0	0
		PRECIP	Print precipitation rate	0	1
		SENSHEAT	Print sensible heat flux	0	0
		CONVZI	Print convective mixing height (Zic)	0	0
		LDB	Print met data and internal variables)	F	F
		NN1	Test and debug print options: first time step	1	1
		NN2	Test and debug print options: last time step	1	1
		LDBCST	Test and debug print options: distance to land internal variables	F	F
		IOUTD	Test and debug print options: control variables for writing winds	0	0
		NZPRN2	Test and debug print options: number of levels starting at sfc	1	1
		IPR0	Test and debug print options: interpolated winds	0	0
		IPR1	Test and debug print options: terrain adjusted surface wind	0	0
		IPR2	Test and debug print options: smoothed wind and diverge fields	0	0
		IPR3	Test and debug print options: final wind speed and direction	0	0
		IPR4	Test and debug print options: final divergence	0	0
		IPR5	Test and debug print options: winds after Kinematic effects	0	0
		IPR6	Test and debug print options: winds after Froude No. adjustment	0	0
		IPR7	Test and debug print options: winds after slope flow	0	0
		IPR8	Test and debug print options: final winds	0	0

Input Group	Subgroup	Variable	Description	Default	Alaska BART
4 - Meteorological data options		NOOBS	No observation mode	0	1
		NSSTA	Number of surface stations	User defined	45
		NPSTA	Number of precipitation stations	User defined	3583 (8 obs + MM5 Pseudo sites)
		ICLOUD	Gridded cloud fields	0	0
		IFORMS	Surface met data file format	2	2
		IFORMP	Precipitation data file format	2	2
		IFORMC	Cloud data format	2	2
5 - Wind field options and parameters		IWFCOD	Wind model options	1	1
		IFRADJ	Compute Froude number adjustment effects	1	1
		IKINE	Compute Kinematic effects	0	0
		IOBR	Use O'Brien procedures for adjust vertical velocity	0	0
		ISLOPE	Compute slope effects	1	1
		IEXTRP	Extrapolate sfc wind obs to upper levels	-4	-4
		ICALM	Extrapolate sfc winds even if calm	0	0
		BIAS	Surface/upper weighting factors (BIAS (NZ))	NZ*0	10*0
		RMIN2	Minimum distance for extrapolation of winds	4	4
		IPROG	Use prognostic model winds as input to diagnostic wind model	0	14
		ISTEPPG	Timestep (hours) of prognostic model data	1	1
		IGFMET	Use coarse CALMET fields as initial guess	0	0
		LVARY	Use varying radius of influence	F	F
		RMAX1	Maximum radius of influence in surface layer (km)	User defined	15
		RAMX2	Maximum radius of influence over land aloft (km)	User defined	15
		RMAX3	Maximum radius of influence over water (km)	User defined	20

Input Group	Subgroup	Variable	Description	Default	Alaska BART
		RMIN	Minimum radius of influence in wind field interpolation (km)	0.1	0.1
		TERRAD	Radius of influence of terrain features (km)	User defined	5
		R1	Relative weight at surface of 1st guess fields and obs (km)	User defined	2.5
		R2	Relative weight aloft of 1st guess fields and obs (km)	User defined	2.5
		RPROG	Weighting factors of prognostic wind field data (km)	User defined	0
		DIVLIM	Maximum acceptable divergence	0.000005	0.000005
		NITER	Maximum number of iterations in divergence minimum	50	50
		NSMTH	Number of passes in smoothing (NSMITH (NZ))	2, (nxnz-1)*4	1,2,2,3,3,4,4,4,4,4
		NINTR2	Maximum number of stations for interpolation (NINTR2(NZ))	99	10*99
		CRITFN	Critical Froude Number	1	1
		ALPHA	Empirical factor controlling influence of kinematic effects	0.1	0.1
		FEXTR2	Multiplicative scaling factor for extrap of sfc obs to upper layers (FEXTRS(NX))	NZ*0.0	10*0
		NBAR	Number of barriers to interpolation of wind fields	0	
		KBAR	Level (1 to NZ) up to which barriers apply	NZ	10
		XBBAR (NBAR>0)	X coordinate of beginning of each barrier (km)	User defined	0
		YBBAR (NBAR>0)	Y coordinate of beginning of each barrier (km)	User defined	0
		XEBAR (NBAR>0)	X coordinate of ending of each barrier (km)	User defined	0
		YEBAR (NBAR>0)	Y coordinate of ending of each barrier (km)	User defined	0
		IDIOPT1	Compute surface temperature	0	0
		ISURFT [b]	Sfc met station to use for sfc temp	User defined	18 (Anchorage)
		IDIOPT2	Domain-averaged temp lapse rate	0	0
		IUPT (IDIOPT2=0) [b]	UA station to use for the domain-scale lapse rate	User defined	1

CALMET 5.8 (070623) Input Variable Selection

Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	Alaska BART
		ZUPT (IDIOPT2=0)	Depth through which domain-scale lapse rate is computed (m)	200	200
		IDIOPT3	Domain-averaged wind component	0	0
		IUPWIND (IDIOPT3=0)	UA station to use for domain-scale winds	-1	-1
		ZUPWIND (IDIOPT3=0)	Bottom and top of layer thru which domain winds computed (m)	1., 1000	1.,1000
		IDIOPT4	Read observed surface wind components	0	0
		IDIOPT5	Read observed upper wind components	0	0
		LLBREZE	Use lake breeze module	F	F
		NBOX	Number of lake breeze regions	User defined	0
		XG1	X grid line 1 defining the region of interest	User defined	0
		XG2	X grid line 2 defining the region of interest	User defined	0
		YG1	Y grid line 1 defining the region of interest	User defined	0
		YG2	Y grid line 2 defining the region of interest	User defined	0
		XBCST	X point defining the coastline (km)	User defined	0
		YBCST	Y point defining the coastline (km)	User defined	0
		XECST	X point defining the coastline (km)	User defined	0
		YECST	Y point defining the coastline (km)	User defined	0
		NLB	Number of stations in the region (sfc + upper air)	User defined	0
		METBXID	Station ID's in the region (METBXID (NLB))	User defined	0
6 - Mixing height, temperature and precipitation parameters		CONSTB	Mix ht constant: neutral, mechanical equation	1.41	1.41
		CONSTE	Mix ht constant: convective equation	0.15	0.15
		CONSTN	Mix ht constant: stable equation	2400	2400
		CONSTW	Mix ht equation: over water	0.16	0.16
		FCORIOL	Absolute value of Coriolis parameter	0.0001	0.0001

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	Alaska BART
		IAVEZI	Spatial averaging of Mix ht: conduct spatial averaging	1	1
		MNMDAV	Spatial averaging of Mix ht: Max search radius (# of grid cells)	1	1
		HAFANG	Spatial avg'n of Mix ht: 0.5-angle of upwind cone for avg (deg)	30	30
		ILEVZI	Spatial averaging of Mix ht: Layer of winds used in upwind	1	1
		IMIXH	Zic Mix Ht Options: Method to compute Mix ht	1	-1
		THRESHL	Zic Mix Ht Options: Threshold buoyancy flux reqrd to sustain over land (W/m3)	0.05	0.0
		THRESHW	Zic Mix Ht Options: Threshold buoyancy flux reqrd sustain over water (W/m3)	0.05	0.05
		ITWPROG	Overwater temp, air-sea temp, & lapse rates	0	0
		ILUOC3D	Zic Mix Ht Options: Land use category in 3D.DAT	16	16
		DPTMIN	Min potential Temp lapse rate in stable layer above Zic (deg-K/m)	0.001	0.001
		DZZI	Depth of computing capping lapse rate (m)	200	200
		ZIMIN	Minimum over land mixing height (m)	50	50
		ZIMAX	Maximum over land mixing height (m)	3000	3000
		ZIMINW	Minimum over water mixing height (m)	50	50
		ZIMAXW	Maximum over water mixing height (m)	3000	3000
		ICOARE	Over water surface fluxes methods and parameters	10	0
		DSELF	Coastal/shallow water length scale (km)	0	0
		IWARM	COARE warm layer computation	0	0
		ICOOL	COARE cool skin layer computation	0	0
		ITPROG	3D temp from obs or from prognostic data	0	1
		IRAD	Temp interpolation type	1	1

CALMET 5.8 (070623) Input Variable Selection
Proposed for Alaska BART Simulations, January 2002 Example

Input Group	Subgroup	Variable	Description	Default	Alaska BART
		TRADKM	Radius of influence of temp interpolation (km)	500	500
		NUMTS	Max number of stations to include in interpolation	5	5
		IAVET	Conduct spatial averaging of temp	1	1
		TGDEFB	Default temp gradient below mix ht over water (deg-K/m)	-0.0098	-0.0098
		TGDEFA	Default temp gradient above mix ht over water (deg-K/m)	-0.0045	-0.0045
		JWAT1	Beginning land use categories for temp interpolation over water	User defined - 999	55
		JWAT2	Ending land use categories for temp interpolation over water	User defined - 999	55
		NFLAGP	Method of precipitation interpolation	2	2
		SIGMAP	Radius of influence for precipitation (km)	100	25
		CUTP	Minimum precipitation rate cutoff (mm/hr)	0.01	.01
7 -Surface meteorological station parameters		CSNAM	Station name	User defined	PAAQ etc
		IDSSTA	Station identification number	User defined	702740 etc
		XSSTA	X-coordinate (km)	User defined	102.119 etc
		YSSTA	Y-coordinate (km)	User defined	290.735 etc
		XSTZ	Time zone	User defined	9 etc
		ZANEM	Anemometer height (m)	User defined	10 etc
8- Upper air meteorological station parameters		CUNAM	Station name	User defined	
		IDUSTA	Station identification number	User defined	
		XUSTA	X-coordinate (km)	User defined	
		YUSTA	Y-coordinate (km)	User defined	
		UUTZ	Time zone	User defined	

Input Group	Subgroup	Variable	Description	Default	Alaska BART
9 Precipitation station parameters		CPNAM	Station name	User defined	0001 etc
		IDPSTA	Station identification number	User defined	500280 (Anchorage) etc
		XPSTA	X-coordinate (km)	User defined	52.323 etc
		YPSTA	Y-coordinate (km)	User defined	241.527 etc

ENVIROPLAN CONSULTING

Final BART Determination Report
Golden Valley Electric Association (GVEA)
Best Available Retrofit Technology (BART) Evaluation

Prepared for

State of Alaska
Department of Environmental Conservation
Division of Air Quality

ADEC Contract No. 18-3001-17
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Enviroplan Consulting Project No. 209928.15
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EXECUTIVE SUMMARY

In accordance with 18 AAC 50.260(j), the Alaska Department of Environmental Conservation (the Department) undertook a review of the Best Available Retrofit Technology (BART) control analysis submitted under 18 AAC 50.260(e)-(h) by Golden Valley Electric Association (GVEA) for the Healy Unit 1 power plant. The BART control analysis was prepared by GVEA for the Healy Power Plant pursuant to the Federal Regional Haze Rule, 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule*; and the Department's regulation relating to BART, 18 AAC 50.260. Pursuant to 40 CFR 51, Appendix A, a BART engineering analysis requires the use of six statutory factors for any BART-eligible source that is found to cause or contribute to atmospheric visibility impairment in any of 156 federal parks and wilderness areas protected under the regional haze rule (i.e., mandatory Class I areas).

The Department contracted Enviroplan Consulting to conduct a review and provide a findings report for guidance for machining a BART determination. Enviroplan was to determine whether the analysis conformed to the WRAP modeling protocol and the related rules and regulatory guidance, including: 18 AAC 50.260(e) - (h); Guidelines for best available retrofit technology under the regional haze rule; 40 CFR 51, Appendix Y; Guidelines for BART Determinations Under the Regional Haze Rule; and U.S. EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA-454/B-03-005, September 2003). The review also accounted for comments through the Public Notice process.

The objective of the review, the initial Findings Report, and this BART Determination Report (Final Report) is to document Enviroplan's findings and recommendations regarding GVEA's BART control analysis. Enviroplan initially conducted a review of the July 28, 2008, BART control analysis to determine compliance with 18 AAC 50.260(e)-(h). In response to requests from the Department and Enviroplan, GVEA submitted supplemental information on October 3, 2008; November 11, 2008; and December 10, 2008. GVEA revised and resubmitted the July 2008 report on January 2, 2009. GVEA provided additional relevant supplemental information on March 18, 24, and 30, 2009. Enviroplan prepared a findings report containing a proposed preliminary BART determination for each BART-eligible source at this facility, consistent with 18 AAC 50.260(j). The April 27, 2009 findings report concluded that the GVEA BART control analysis complied with 18 AAC 50.260(e)-(h).

In the April 2009 Findings Report, Enviroplan proposed, and the Department approved, a preliminary BART determination for Healy 1 as the existing dry sorbent injection system (SO_2); the addition of a SCR system (NO_x); and the existing reverse gas baghouse system (PM_{10}). For Auxiliary Boiler #1, the existing configuration (i.e., no air pollution control systems) was determined to be BART.

The Department public noticed the April 2009 Findings Report and proposed BART determination for the Healy plant on May 12, 2009. The 35-day public comment period occurred from May 12, 2009 through June 15, 2009. Comments received were addressed in a Response to Comment (RTC) document. In response to comments, the April 27 Findings Report was revised and adjusted. The revised report is called the Final GVEA BART Determination Report (Final Report). This Final Report, which was issued by the Department to GVEA under a February 9, 2010 cover letter, provides the recommended final BART determination for the Healy plant pursuant to 18 AAC 50.260(l), taking into account as necessary the comments and additional information received during the comment period. This Final Report also takes into account certain decisions made by the Department regarding an informal review request submitted by GVEA on February 24, 2010. The Department's decision on the entirety of GVEA's request has been issued under a separate letter dated April 12, 2010; however, this Final Report is revised to correct deficiencies in the January 19, 2010 Final Report identified by GVEA in their request.

Similar to the April 2009 Findings Report, the purpose of the Final Report is to document Enviroplan's findings regarding GVEA's BART control analysis in terms of compliance with 18 AAC 50.260(e)-(h); and recommend a final BART determination pursuant to 18 AAC 50.260(l), including required pollutant specific emission limits for affected emission units. This Final Report concludes that the GVEA BART control analysis complies with 18 AAC 50.260(e)-(h). For Healy Unit 1, Enviroplan recommends final BART determination emission limits as follows:

BART Emission Limits

The final BART emission limits recommended for Healy Unit 1 are summarized in the table below. The BART emission limits are based on an 8-year remaining useful life for Healy 1 (from calendar year 2016) which is provided for at Section IV.D.4.K of 40 CFR 51, Appendix Y (federal BART rule). The emission limits are compared to current permitted pollutant emission limits which remain in effect.

Table E-1: Final BART Emission Limits Recommended for the GVEA Healy Power Station

	Particulate		**SO_2**		**NOx**	
	Current [1]	BART [2]	Current [1]	BART [2]	Current [1]	BART [2]
Healy Unit 1	0.05 gr/dscf 36.7 lb/hr (hourly average at full load) 161 ton/yr	0.015 lb/MMBtu (based on compliance source testing)	258 lb/hr (24-hour average, calendar day) 367 lb/hr (3-hour average) 472 ton/yr	0.30 lb/MMBtu (30-day rolling average) [3]	429 ton/yr	0.20 lb/MMBtu (30-day rolling average)
Auxiliary Boiler #1	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average 1 ton per calendar year	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average	0.3% S in oil, annual average 0.5% S in oil, 3-hour average	0.53 lb/MMBtu (30-day rolling average)	20 lb NOx/1000 gal distillate fuel, annual average 20% load factor, annual average	0.15 lb/MMBtu (30-day rolling average).

1. Taken from Permit No. 173TVP01, Table 2.
2. BART emission limits for Unit 1 are in addition to the current (existing) emission limits. The BART emission limit for particulate reflects filterable PM_{10}.

The existing uncontrolled configuration for Auxiliary Boiler #1 is considered as final BART since the predicted daily visibility impacts for this unit are well below the significant visibility impairment metric of 0.5 daily deciviews. There is no change in the final BART determination for

Auxiliary Boiler #1 (i.e., no controls; current TV permit emission limitations including equivalent limitations in units of lb/MMBtu). Details on the final BART determination for Healy 1 are presented in Section 8.

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1. INTRODUCTION

1.1 General Program Background

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). The rule is codified at 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y. The Regional Haze Rule requires certain States, including Alaska, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary BART-eligible source that might cause or contribute to impairment of visibility in a Class I Area. BART-eligible sources include those sources that:

1. have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
2. were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
3. whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301.

During 2007 the Department developed a list of Alaska BART-eligible sources based on the federal BART guidelines. GVEA's power plant in Healy, Alaska has been identified by the Department as required to conduct BART assessments for its BART-eligible emission units, Healy Unit 1 and Auxiliary Boiler #1. The affected visibility impairing pollutants (VIP) are NO_x, SO_2 and particulate matter (conservatively as PM_{10}). The requirements applicable to Alaska BART-eligible sources were published by the Department on December 30, 2007 under 18 ACC 50.260. The Department's BART regulation requires sources not exempt from applicability based on a visibility modeling analysis to submit a case-by-case BART proposal for each BART-eligible unit at the facility and for each VIP by July 28, 2008.

A preliminary regional BART screening modeling analysis of all BART-eligible sources in Alaska was completed in 2007 by the Western Regional Air Partnership (WRAP) - Regional Modeling Center (RMC). The simulations were done using the CALPUFF modeling system and a single year, 2002, of processed MM5 CALMET data. The simulations were performed to evaluate predicted impacts of visibility in Alaska PSD Class I areas, including the Denali National Park and Preserve (DNPP) and Tuxedni Wilderness Area. BART-eligible sources are exempt from BART if the daily visible impacts at a Class I area are below the screening criteria set by the Department (ADEC), EPA, and the Federal Land Managers (FLMs). Pursuant to 18 AAC 50.260(q)(4), a 0.5 or greater daily deciview change when compared against natural conditions is considered to "cause" visibility impairment.

The initial modeling analysis conducted by WRAP - RMC indicated that the maximum visibility impact of GVEA's facility at the DNPP Class I area was higher than the 0.5 daily deciview visibility screening threshold, while the impacts at Tuxedni were below this threshold. The Department notified GVEA in December 2007 that they were subject to the BART control analysis requirements for the affected equipment since the WRAP – RMC analysis was unsuccessful at providing a basis for exemption. The Department identified the DNPP as the affected Class I area.

GVEA submitted the requisite BART control analysis and preliminary determinations on July 28, 2008. GVEA provided supplemental information on October 3, 2008, November 11, 2008 and December 10, 2008, in response to the Department's contractor, Enviroplan's, September 19, 2008 and October 16, 2008 requests for clarification. After further discussions with the Department and Enviroplan, GVEA submitted a revised BART analysis report on January 2, 2009. Enviroplan reviewed this information and prepared a draft findings report on January 27, 2009. Teleconferences then occurred between the Department, GVEA, CH2M Hill (GVEA's consultant) and Enviroplan on February 25 and 27, 2009 and March 2, 2009. As a follow-up to these teleconferences, GVEA submitted additional supplemental study information on March 18, 24 and 30, 2009.

Pursuant to 40 CFR 51, Appendix A, a BART engineering analysis requires the use of six statutory factors for any BART-eligible source that is found to cause or contribute to atmospheric visibility impairment in any of 156 federal parks and wilderness areas protected under the regional haze rule (i.e., mandatory Class I areas). These factors include: 1) the available retrofit options, 2) any pollution control equipment in use at the source (which affects the availability of options and their impacts), 3) the costs of compliance with control options, 4) the remaining useful life of the facility, 5) the energy and non-air quality environmental impacts of control options, and 6) the visibility impacts analysis.

GVEA conducted the BART control analysis utilizing the above referenced factors. The GVEA analysis concluded that the BART-eligible sources at the Healy Power Plant do not require additional retrofit controls because the potentially feasible control options are either not cost effective, the control options do not result in significant visibility benefit, and/or the cost of visibility improvement resulting from potentially installing these control options are highly cost prohibitive. GVEA considers the existing controls and operating practices on BART-eligible sources at the facility as BART.

The Department contracted Enviroplan Consulting to review the aforementioned GVEA preliminary BART determination to determine whether the analysis conformed to the WRAP modeling protocol and the related rules and regulatory guidance, including: 18 AAC 50.260(e) - (h); Guidelines for best available retrofit technology under the regional haze rule; 40 CFR 51, Appendix Y; Guidelines for BART Determinations Under the Regional Haze Rule; and U.S. EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA-454/B-03-005, September 2003). The review also accounted for comments provided by the National Park Service (NPS) in response to a Department-NPS teleconference of February 10, 2009, wherein preliminary BART control recommendations (from Enviroplan's January 27, 2009 draft findings report) were discussed. The NPS provided the Department with initial comments on February 10, 2009 (verbal) and February 12, 2009 (written as an email). The review also considered all supplemental information provided by GVEA through the end of March 2009.

Enviroplan prepared a BART review Findings Report that was submitted to the Department on April 27, 2009. The report included a recommendation of *proposed* BART controls and related SO_2, NO_x and PM_{10} emission limits for Healy Unit 1. The Department agreed with the Findings Report conclusions and public noticed the BART proposal 35 day comment period from May 12, 2009 though June 15, 2009.

The Department received comments on the proposed BART determination and requested that Enviroplan review each comment and prepare a separate Draft Response to Comments (RTC) document. The RTC document, which specifies the commenter; each of their comments; and detailed responses to the comments, including any changes to data, information and/or conclusions found in April 27, 2009 Findings Report, has been submitted by Enviroplan to the Department.

Based on the above, Enviroplan has incorporated the changes described in the RTC in this version of the findings report, which is now labeled as the "BART Determination Report." The following sections of this document present the revised and final review findings, which includes information from the April 27, 2009 Findings Report as applicable, as well as any updated information submitted to the Department during the comment period that clarifies or alters the conclusions of the April 27, 2009 Findings Report. However, detailed discussions associated with such changes are relegated to the RTC document, and are only summarized as necessary herein. This Final Report also corrects for certain deficiencies and errors identified by GVEA in their February 24, 2010 informal review request, and approved for correction by the Department under a separate letter dated April 12, 2010.

1.2 Source (BART eligible units) Description and Background

Healy 1 is a nominal 25-MW unit located in Healy, Alaska, approximately 8 kilometers (5 miles) from DNPP. The unit is a wall-fired, wet bottom boiler manufactured by Foster Wheeler. Low NO_x burners (LNB) and over-fired air (OFA) ports were installed in 1996. Particulate emissions are collected by a reverse gas baghouse installed in the early 1970s. Sulfur oxides are controlled by a dry sorbent injection system installed in 1999. At the present time sodium bicarbonate is the sorbent which is injected into the flue gas after the air heater.

Comments received from GVEA on June 15, 2009 in response to the proposed BART public notice period (May 12, 2009 - June 15, 2009) included a clarification that the Healy 1 expected "*remaining useful life*", as this term is defined in the regional haze rule and the BART Guideline (i.e., 40 CFR 51, Appendix Y), is about 15 years. GVEA also indicated the useful lifetime of Healy 1 to be 55 years.

Auxiliary Boiler #1 is only used to supply heat to the Healy 1 building during shutdown periods or during emergency repairs to Healy 1. Auxiliary Boiler #1 also provides steam for water processing and hot potable water to the Healy Clean Coal Project (HCCP) if called for during periods when Healy 1 is not operating. The unit is also fired monthly for maintenance checks.

2. ELEMENTS OF THE BEST AVAILABLE RETROFIT TECHNOLOGY ANALYSIS

On July 1, 1999 (40 CFR Part 51), EPA published the Regional Haze Rule which provides the regulations to improve visibility in 156 national parks, wilderness areas, and international parks which were in existence in 1977. One of the key elements of the Regional Haze rule addresses the installation of BART for certain source categories that were built and in operation between 1962 and 1977. BART is defined as:

> *"an emissions limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emissions limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."*

BART, also referred to as the "Clean Air Visibility Rule" (CAVR), requires states to identify "BART-eligible" sources. Sources need to meet all three criteria to be considered "BART-eligible" including:

1. The source belongs to one of the 26 listed source categories; these categories are same as those for Prevention of Significant Deterioration (PSD) applicability analysis;
2. The source was installed (constructed) and in operation between 1962 and 1977; and
3. The source emits more than 250 tons per year of any one or all of the visibility impairing pollutants including sulfur dioxide (SO_2), nitrogen oxide (NO_2), or particulate matter (PM_{10}). Volatile organic compounds (VOC) and ammonia (NH_3) may be included depending on the state in which the source is located.

The Alaska BART rule (18 AAC 50.260(f)) requires BART analysis to be conducted for NO_x, SO_2, and PM_{10} only (i.e., visibility impairing pollutants). The BART analysis identifies the best system of continuous emission reduction taking into account:

1. The available retrofit control options,
2. Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
3. The costs of compliance with control options
4. The remaining useful life of the facility,
5. The energy and non-air quality environmental impacts of control options, and
6. The visibility impacts analysis.

The five basic steps of Case-by-Case BART Analysis are:

STEP 1—Identify All Available Retrofit Control Technologies.

In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.

STEP 2—Eliminate Technically Infeasible Options.

Technologies demonstrated to be infeasible based on chemical, physical, and engineering principles are excluded from further consideration.

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies.

Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to Best Available Control Technology (BACT) analyses.

STEP 4—Evaluate Impacts and Document the Results, and

Impacts that should be considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts and the remaining useful life of the unit to be controlled.

STEP 5—Evaluate Visibility Impacts.

Modeling should be performed on the pre- and post-control emissions to determine the actual impact on visibility. This step does not need to be performed if the most stringent control technology is chosen.

The following sections of this report review the BART evaluation steps performed by GVEA for Healy Unit 1. As discussed in Section 7 of this report, the predicted visibility impacts for Auxiliary Boiler #1 are well below the 0.5 daily deciview metric established to determine if source emissions will cause or contribute to visibility impairment. Enviroplan agrees with GVEA that, pursuant to 40 CFR 51, Appendix Y, this insignificant source is not subject to the above detailed analyses and the existing configuration is deemed as BART.

The above determination notwithstanding, GVEA submitted an informal review request to the Department on February 24, 2010. GVEA indicated as part of their submittal that the BART NO_x and SO_2 emission limits specified by Enviroplan for Auxiliary Boiler #1 were erroneous. The Department evaluated this assertion and determined that a decimal placement error occurred when the Department converted the Title V operating permit limits for NO_x and SO_2 into a format needed for visibility modeling. Both WRAP and GVEA used these emission rates, which were understated by three orders of magnitude, in their respective visibility modeling analyses. As such, the Department requested Enviroplan to revise the prior GVEA visibility modeling analysis using the correct Auxiliary Boiler #1 emission rates. Enviroplan performed the revised analysis and determined the predicted visibility impacts attributable to the boiler remain below 0.5 deciviews. Enviroplan's analysis and findings are summarized in a memorandum to the Department, included herein as Appendix B. The Department's BART determination for

Auxiliary Boiler #1 remains the existing configuration and the current Title V emission limits (see Tables E-1 and 9-1).

Enviroplan's previous GVEA BART evaluation findings report, dated April 27, 2009, recommended proposed BART controls and NO_x, SO_2 and PM_{10} emission limits for Healy Unit 1. The Department public noticed the April 27, 2009 BART proposal for 35-days (May 12, 2009 - June 15, 2009). Comments were received during the public notice period, and these comments have been addressed in a separate Response to Comments (RTC) document. As such, the following sections of this BART Determination Report include relevant April 27, 2009 proposed BART findings; new information from the RTC as necessary; and revised control costs and conclusions as appropriate.

3. IDENTIFICATION OF ALL AVAILABLE RETROFIT EMISSION CONTROL TECHNOLOGIES (Step 1)

3.1 NO_x Control Technologies Considered

The following describes the NO_x retrofit technologies deemed by GVEA as potentially feasible for Healy Unit 1. Although not specifically listed below, the existing low NO_x burner/over fire air system is also a feasible NO_x control technology. Enviroplan finds that GVEA has satisfied the BART step 1 requirement, with any additional finding(s) specific to a control option indicated as necessary below.

Optimizing the Existing Low NO_x Burner/Over-Fire Air System (LNB/OFA)

The mechanism used to reduce NO_x emissions with low NO_x burners is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char.

Healy 1 currently has an LNB/OFA system which was installed in 1996. This system has been operating for an extended period of time, and, as indicated by GVEA, while plant personnel have exerted considerable effort to optimize performance (minimize CO within the existing permit NO_x limits), it has not been optimized with the goal of minimizing NO_x emissions. Optimization of the LNB/OFA system could be attempted by utilizing a boiler system consultant with the intent of reaching a guideline NO_x target emissions of 0.23 lb/MMBtu (i.e., the 30-day rolling BART presumptive limit for a 200 MW unit). GVEA is uncertain whether such a limit would be achievable, and have indicated that minimizing NO_x emissions will likely also impact other boiler operating parameters such as loss on ignition (LOI), carbon monoxide (CO), and excess air. GVEA further indicated that the 1994 PSD permit (for HCCP) resulted in extensive discussion between ADEC and GVEA in terms of the need to minimize CO emissions from Healy 1. Based on this indication, GVEA has indicated that BART control options must consider the impact on all emissions when attempting to reduce NO_x.

Relating to the above, Enviroplan requested on October 13, 2008 that GVEA provide additional information on the CO emissions minimization issue. GVEA provided a response on November 11, 2008, which included correspondence letters from 2002 and 2005 between GVEA and ADEC. The correspondence indicated that CO emissions from Healy Unit 1 increased after the LNB/OFA installation was completed in 1998. ADEC indicated the need to minimize CO emissions from Healy Unit 1 through combustion system optimization without sacrificing the unit's low NO_x emissions. However, no permit limit was established for CO emissions from Healy Unit 1.

In addition to the above, GVEA indicated in their November 11, 2008 response that the potential for CO emissions increases were associated not just with the LNB/OFA optimization retrofit scenario; but also with the use of ROFA® (described below) since LNB modification would occur with a ROFA system. Overall, the information and correspondence pertaining to CO emissions as provided by GVEA is acknowledged. It is also understood that such collateral impacts can be considered as an additional environmental impact under the Energy, Environmental and Economic Impacts portion of the BART review process (i.e., Step 4).

However, since visibility impairing pollutants are the focus of BART (i.e., NO_x and not CO); and since there may not be an increase in CO emissions from improved LNB/OFA NO_x control, Enviroplan finds that this is informational only and is not considered further in this review.

Rotating Opposed Fire Air (ROFA®)

Mobotec markets ROFA® as an improved second generation OFA system whereby the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively. A typical ROFA® installation would have a booster fan(s) to supply the high-velocity air to the ROFA® boxes. GVEA noted that Mobotec proposed one 200 horsepower (hp) fan for Healy 1. Mobotec expects to achieve a NO_x emission rate of 0.15 lb/MMBtu using ROFA® technology.

ROFA® with Rotamix®

The Mobotec Rotamix® system is an advanced selective non-catalytic reduction (SNCR) system (also see below) that has been developed to optimize the reduction of unwanted substances, such as NO_x. To optimize NO_x reduction, an amine-based reagent such as ammonia is added. The ammonia is added using lances that are inserted in the ROFA®/Rotamix® nozzles. The high-velocity air in the ROFA® system carries the chemicals into the center of the furnace. Mobotec expects to achieve a NO_x emission rate of 0.11 lb/MMBtu using ROFA/Rotamix® technology.

Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) is a post-combustion NO_x control technology based on the reaction of NH_3 and NO_x. SNCR involves injecting urea/NH_3 into the combustion gas path to reduce the NO_x to nitrogen and water. SNCR is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or more commonly urea is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The ammonia may render fly ash unmarketable, react with sulfur to foul heat exchange surfaces, and/or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization efficiency and higher operating cost.

Selective Catalytic Reduction (SCR)

SCR is a process that involves post combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x

decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and design of the NH_3 injection system.

Reduction catalysts are divided into two groups: platinum and base metal (primarily vanadium or titanium). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_x ratio, and optimum oxygen concentration. A disadvantage common to both platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but also have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NO_x emissions) or ammonium nitrate.

Sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in gas and the mercaptans used as an odorant) to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. Sulfur trioxide and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled or may be emitted from the stack as increased emissions of PM_{10}/$PM_{2.5}$. Fouling can eventually lead to increased system pressure drop over time and decreased heat transfer efficiencies.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result of either prolonged exposure to excessive temperatures, or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a 3-year lifetime to achieve low emission levels for high performance catalyst systems.

SCR manufacturers typically estimate 10 to 20 ppm of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which results in ammonia slip. Ammonia slip may increase atmospheric PM formation, which is a visibility impairing pollutant. Thus, an emissions trade off between NO_x and ammonia occurs in high NO_x reduction applications. While SCR may be considered potentially technically feasible for the boilers, there are various concerns with the technology, most notably the temperature required for the catalyst to activate and the unreacted ammonia introduced into the exhaust stream.

SCR works on the same principle as SNCR, but a catalyst is used to promote the reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F to 750°F. Due to the catalyst, the SCR process is more efficient than SNCR. The most common type of SCR is the high-dust configuration, where the catalyst is located upstream of the airheater and downstream from the economizer.

3.2 SO_2 Control Technologies Considered

The following describes the SO_2 retrofit technologies deemed by GVEA as potentially feasible for Healy Unit 1. Although not specifically listed below, the existing dry sorbent flue gas desulfurization (FGD) system is also a feasible SO_2 control technology. Enviroplan finds that GVEA has satisfied the BART step 1 requirement, with any additional finding(s) specific to a control option indicated as necessary below.

Increase sodium bicarbonate injection rate to improve SO_2 removal utilizing the existing dry sorbent injection system

Healy 1 currently operates a dry sorbent injection system which injects sorbent into the flue gas after the air heater and upstream of the baghouse or fabric filter to control SO_2 emissions. Since the system was installed in 1999, GVEA has used three different materials as sorbent in an attempt to maximize the efficiency of the system. When the system was first installed, calcium carbonate was used as the sorbent. Several years later GVEA began experimenting with trona (a sodium sesquicarbonate) and was able to increase SO_2 capture significantly. In 2007, GVEA was able to optimize the system even further by using sodium bicarbonate. The SO_2 in the flue gas reacts with the sodium bicarbonate to form dry particles, which are captured downstream in the existing fabric filter. Under current operation, the dry sodium bicarbonate system consistently achieves approximately 40 to 50 percent removal of SO_2. An increase in the amount of sodium bicarbonate injected may have the potential to achieve SO_2 removal of up to 70 percent.

GVEA has indicated that there are several significant potential issues related to increasing sodium bicarbonate injection with the existing dry sorbent injection system as follows:

1. The existing sorbent injection system design and equipment may not be able to support the required sodium bicarbonate feed rate to remove SO_2 continuously at 70 percent removal. While it may be possible to achieve 70 percent removal on a short-term basis, it is not feasible to operate the existing equipment at that rate continuously with no interruptions.
2. A brown NO_2 plume may be visible at higher SO_2 removal rates based on operational experience on other similar dry sodium injection systems. It is uncertain whether a brown plume would be visible at a 70 percent removal rate.
3. From previous testing at Healy 1 in March 2008, higher sodium bicarbonate injection rates corresponded with higher mercury emissions.

GVEA has indicated that, while it may be possible to operate the current SO_2 FGD system up to a 70 percent removal capability for some periods of time, consistently achieving this removal rate is not feasible when taking into account equipment capacities, SO_2 removal performance, and other environmental impacts. To this end, GVEA submitted additional information on March 18, 2009 pertaining to the optimization of their existing FGD system. The information included re-computed sorbent usage costs; as well as capital costs associated with the installation of new injectors (redundant injection system) needed to achieve a continuous SO_2 removal efficiency of 70 percent. Further information was provided by GVEA on August 27, 2009, in response to an August 17, 2009 request for clarification from the Department. Additional discussion relating to the optimization of the existing FGD system, which is deemed to be a technologically feasibly retrofit option, is presented in Section 6.2 of this report.

With respect to the brown plume issue, Enviroplan agrees with GVEA on the potential for an increased occurrence of visible plumes with increased sorbent usage. A brief literature review performed by Enviroplan (see footnotes *1, 2 and 3* for example) confirmed that the use of sodium reagents in FGD systems can result in the production of a reddish-brown plume coloration in stack gases downstream of the particulate control device. One document opines the belief that some step within the overall sulfation reaction (reaction of sodium reagent with SO_x) initiates the oxidation of NO to NO_2. It is the presence of the NO_2 in the exiting flue gases which is the source of the plume coloration. While the frequency of plume occurrence and possible impacts at DNPP is not possible to predict, Enviroplan does agree that an increase in sorbent usage to reduce SO_2 may be offset with potential deleterious effects on visibility due to brown plume events.

With respect to the increased mercury emissions issue, Enviroplan reviewed GVEA's March 2008 mercury test summary report and found that an increase in sodium bicarbonate sorbent injection rate corresponded to an increase in elemental mercury (Hg) emissions at the FGD system. GVEA has not provided any detailed explanation for this outcome and, as such, the test result is considered to be informational and not deemed as a viable reason to eliminate increased sorbent injection as a retrofit option.

Install lime spray dryer FGD system

The lime spray dryer is a semi-dry sorbent based system that typically injects lime slurry in the top of an installed absorber vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form dry calcium sulfate particles. At Healy 1, this dry particulate matter would be captured downstream in the existing baghouse, along with the fly ash. It is assumed that a lime spray dryer system will produce a dry waste product suitable for landfill disposal. Operation of a lime spray dryer FGD system would result in a wet plume, reduced plume rise, and the potential for higher near field air quality impacts.

Install wet limestone FGD system

Wet limestone FGD systems operate by treating the flue gas in large scrubber vessels with a limestone solution. Wet FGD scrubbers use an absorber tower in which flue gas is contacted by the limestone slurry, resulting in conversion of SO_2, in the flue gas into calcium sulfate (gypsum), with carbon dioxide (CO_2) going up the stack. The calcium sulfate is removed from the scrubber and disposed, and it is assumed that the waste product from a wet limestone scrubber system is suitable for landfill disposal. Operation of a wet limestone FGD system would result in a wet plume, reduced plume rise, and the potential for higher near field air quality impacts.

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[1]Yougen Kong and Jim Vysoky, "Comparison of Sodium Bicarbonate and Trona for SO_2 Mitigation at A Coal-Fired Power Plant", Solvay Chemicals Inc., presented at ELECTRIC POWER 2009, Rosemont, Illinois, May 12-14, 2009.
[2]U.S. EPA. "Multipollutant Emission Control Technology Options for Coal-Fired Power Plants, EPA-600/R-05/034, March 2005.
[3]"Method For Baghouse Brown Plume Pollution Control", WO/1989/009184, Inventor/Applicant: Richard G. Hooper, taken from World Intellectual Property Organization, http://www.wipo.int/pctdb/en/wo.jsp?IA=US1989001254&DISPLAY=DESC.

3.3 Particulate Control Technologies Considered

Healy 1 currently has a reverse gas baghouse installed for particulate control. The baghouse specifications include 12 compartments, each with 64 bags approximately 33 feet in length and 11.5 inches in diameter, and a design air to cloth ratio of approximately 2.0 with all compartments in service. The baghouse used at Healy 1 achieves a control efficiency of 99.89%. This high efficiency baghouse is a state-of-the-art technology for filterable particulate control for Healy 1. Other control technologies such as a mechanical collector, hot or cold electrostatic precipitators, or wet particulate scrubbers could be considered as additional feasible particulate control options. However, none of these alternative technologies are considered to have the potential of matching the consistent filterable particulate removal performance of a baghouse. Therefore, the existing baghouse is considered BART for Healy 1, and completion of the five-step BART process is not required.

Since GVEA currently uses a high efficiency baghouse for particulate control, Enviroplan agrees with GVEA in finding this control to be BART for this pollutant/emission unit. No additional detailed analyses (steps), including no the visibility modeling analyses, are required for particulate emitted from Healy 1, pursuant to 40 CFR 51, Appendix Y, Section IV.D - Step 1.9.

Comments pertaining to this control system were received from the NPS during the proposed BART 35-day notice period (May 12, 2009 - June 15, 2009). One such comment indicated agreement with the existing baghouse being BART for filterable PM_{10}; however, the commenter specified the need to also evaluate controlling condensable PM_{10}.

As indicated above, the existing baghouse is used for control of filterable particulate matter. The baghouse also provides complimentary benefit to the SO_2 control system (sorbent injection into the ductwork prior to the baghouse resulting in dry sulfate particles captured at the baghouse). At this time, control efficiencies for condensable PM are not well understood (e.g., see Federal Register Notice 74 FR 36427, July 23, 2009). Regardless, it is anticipated that the degree of control of condensable PM will be similar between a cold-side ESP and a baghouse. In addition, the baghouse is capable of a higher emission reduction for filterable PM. Hence, at this time, the Department sees no benefit of adding an additional PM_{10} control device in place of, or in addition to, the existing baghouse for controlling condensable PM.

4. TECHNICALLY FEASIBLE RETROFIT EMISSION CONTROL TECHNOLOGIES (Step 2)

4.1 NO_x Control Technologies

GVEA based their technical feasibility on physical constraints, the current boiler configuration and size, and impact on boiler operation and efficiency for Healy 1. A summary showing the results of the evaluation process for the NO_x technologies is provided in Table 4-1 below.

Table 4-1: Technically Feasible NO_x Control Options for Healy 1

Control Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
Current Operation (i.e., LNB w/OFA)	Yes	--
Optimize Existing LNB w/OFA	Yes	--
LNB w/OFA & SNCR	Yes	--
Replace OFA with ROFA®	Yes	--
ROFA® and Rotamix®	Yes	--
LNB w/OFA & SCR	Yes	--

In their report, GVEA stated that each of the control methods identified above is considered technically feasible for controlling NO_x emissions from Healy 1. Except for the SCR option, GVEA did not consider potential space constraints in their analyses. For SCR, GVEA contracted with an SCR application company to conduct an on-site evaluation of the retrofit potential and related costs for this system (see Section 5.1 below).

4.2 SO_2 Control Technologies

GVEA based their technical feasibility on physical constraints, the current boiler configuration and size, and impact on boiler operation and efficiency for Healy 1. A summary showing the results of the evaluation process for the SO_2 technologies is provided in Table 4-2 below.

Table 4-2: Technically Feasible SO_2 Control Options for Healy 1

Control Technology	Technically Feasible and Applicable?	Reasons for Technical Infeasibility
Current Operation	Yes	--
Increase sodium bicarbonate feed rate utilizing existing dry sorbent injection system	Yes	--
Lime Spray Dryer	Yes	--
Wet Limestone FGD System	Yes	--

In their report, GVEA stated that each of the control methods identified above is considered technically feasible for controlling SO_2 emissions from Healy 1. GVEA did not consider potential space constraints in their analyses.

5. EVALUATION OF TECHNICALLY FEASIBLE RETROFIT EMISSION CONTROL TECHNOLOGIES (Step 3)

In this section, Tables 5-1 and 5-2 indicate the control effectiveness for each group of control technologies. The control efficiencies are relative to the current operation of Healy 1 (i.e., the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system). The projected emission rates reflect a 30-day rolling average, consistent with the BART program requirements for an electric generating unit (EGU). The emission limits are based on vendor information and professional engineering judgment, as provided by GVEA.

5.1 NO_x Control Technologies

The expected NO_x emission rates are summarized in Table 5-1 for each of the NO_x removal technologies designated as feasible in Step 2 (previous Section 4).

Table 5-1: Control Effectiveness of the NO_x Control Options for Healy 1

Control Technology	Control(1) Efficiency (%)	Projected Emission Rate (lb/MMBtu)
Current Operation (LNB w/OFA)	-	0.28
Optimize Existing LNB w/OFA	18.0	0.23(2)
LNB w/OFA & SNCR	32.0	0.19
Replace OFA with ROFA®	46.0	0.15
ROFA and Rotamix®	61.0	0.11
LNB w/OFA & SCR	75.0	0.07

(1) Relative to the current controlled baseline emission rate of 0.28 lb/MMBtu.
(2) Presumptive limit for > 200 MW wall fired boilers burning sub-bituminous coal

Three issues are noted with respect to the information presented in Table 5-1. These issues are based on comments received by the Department during the proposed BART 35-day notice period (May 12 2009 - June 15, 2009). First, comments provided by GVEA specified that a NO_x emission rate of 0.28 lb/MMBtu would be more representative of the existing baseline emissions for Healy 1 than 0.25 lb/MMBtu (i.e., the rate reflected in the April 27, 2009 proposed BART Findings Report). This revision was based on a 5-year analysis performed by GVEA of 30-day rolling NO_x emission rates for Healy 1 from CEM data. As indicated in the RTC document, the baseline controlled emission rate for Healy 1 is revised to 0.28 lb/MMBtu.

Second, as discussed in the RTC document, GVEA provided a refined cost analysis for the SCR retrofit option. GVEA contracted Fuel Tech, a consulting company that specializes in SNCR and SCR application, to inspect the Healy plant; gather additional site-specific data; and more fully assess the capital cost impact associated with a retrofit SCR system designed to meet the 0.07 lb/MMBtu preliminary BART NO_x emission limit. Fuel Tech conducted the evaluation and issued a findings report and cost evaluation on June 10, 2009. As indicated by Fuel Tech, their evaluation was not a detailed engineering study and cost analysis, but it did account for actual current systems setup and plant retrofit design limitations and requirements. The BART Guideline supports the use of site-specific design and other conditions that affect the cost of a particular BART analysis. GVEA's revised SCR cost evaluation using the Fuel Tech study data is reflected in this revised findings document.

Third, comments received from the NPS suggested that GVEA's specified SCR NO_x control efficiency and related emission limit were understated. As indicated in the RTC document, due to uncertainty with respect to continuous system operation in a harsh Alaska environment, with only limited time for catalyst cleaning and system maintenance; and consideration of other determinations for this type of control system, the proposed GVEA emission limit of 0.07 lb/MMBtu has been determined to be adequate for this Healy 1 retrofit option.

5.2 SO_2 Control Technologies

Table 5-2 presents the SO_2 control technologies being evaluated and the expected removal efficiencies and emission rates. The control efficiencies are relative to the current operation of Healy 1 (i.e., the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system). The projected emission rates reflect a 30-day rolling average, consistent with the BART program requirements for an electric generating unit (EGU).

Table 5-2: Control Effectiveness of the SO_2 Control Options for Healy 1

Control Technology	Control[(1)] Efficiency (%)	Projected Emission Rate (lb/MMBtu)
Current Operation (dry sorbent injection FGD system)	NA (50)	0.30
Increase sodium bicarbonate feed rate utilizing existing dry sorbent injection system	40 (up to 70)	0.18
Lime spray dryer (semi-dry FGD)	50 (75)	0.15
Wet limestone FGD	77 (88)	0.07

(1) Relative to the current controlled baseline emission rate of 0.30 lb/MMBtu. The value in parenthesis is the control efficiency relative to an uncontrolled baseline emission rate of 0.60 lb/MMBtu determined from analysis of Usibelli Mine coal, as indicated by GVEA on August 27. 2009.

Comments pertaining to the lime spray dryer (LSD) control system were received from the National Park Service (NPS) during the proposed BART 35-day notice period (May 12, 2009 - June 15, 2009). One such comment suggested that GVEA's specified SO_2 control efficiency and related emission limit for this system were understated. This is a similar comment made by the NPS in February 2009 (a response was provided by the Department at that time). As indicated in the RTC document, due to uncertainty with respect to system capability using the very low Usibelli Mine coal (down to 0.17% sulfur by weight); and consideration of other determinations for this type of control system, the proposed GVEA emission limit of 0.15 lb/MMBtu has been determined to be adequate for this Healy 1 retrofit option. This limit is equivalent to the BART rule EGU presumptive limit for SO_2.

6. COST-EFFECTIVENESS AND IMPACT ANALYSIS (Step 4)

GVEA evaluated the cost of implementing each of the technically feasible control technology. The total capital investment for each control technology when applied specifically to the Healy 1 site and the annual operating and maintenance costs were calculated. These cost calculations were based on the following:

- CUECost Workbook, Version 1.0.
- CH2M HILL's internal proprietary database.
- Budgetary quotes from equipment vendors.
- Quotes or cost estimation for previous design/build projects or in-house engineering estimates.
- Site-specific retrofit and cost evaluations for a selective catalytic reduction (SCR) system.

GVEA calculated the cost-effectiveness of each control technology from the cost of implementation and the amount of pollutant reduced. Cost-effectiveness is defined as the cost of control per ton of pollutant removed, and it is determined on an annualized basis. The annual reduction in pollutant emission rate (tons/year) for each retrofit control option is determined relative to a baseline anticipated annual emission rate. As explained by GVEA in their January 2009 final report submittal, the baseline anticipated annual emission rates for Healy 1 (NO_x and SO_2) are derived from the boiler heat input capacity of 340 MMBtu/hr and the average actual emission rates determined from 2008 CEMs data (i.e., (0.28 lb/MMBtu and 0.30 lb/MMBtu for NO_x and SO_2, respectively). The use of annual anticipated pollutant emission rates is consistent with 40 CFR 51, Appendix Y, Section IV.D, Step 4 for purposes of determining cost effectiveness. The current existing respective NO_x and SO_2 emissions control configurations of LNB/OFA and dry FGD for Healy Unit 1 are reflected in these baseline emission rates.

It is noted that the "baseline" emission rates used for cost effectiveness determination purposes, as described above, are not the same "baseline" emission rates used by GVEA in their CALPUFF visibility modeling assessment. For purposes of visibility modeling (see Section 7 of this report), the BART rule requires an affected source to use "peak" 24-hour emission rates as the basis for modeling their pre-control (i.e., existing or baseline) configuration. Peak 24-hour emission rates, which were used by GVEA in their visibility modeling analysis, are higher than the annual anticipated pollutant emission rates described above.

The cost analysis described above was presented in the April 27, 2009 proposed BART Findings Report. Comments pertaining to proposed BART were received from GVEA during the related 35-day notice period (May 12, 2009 - June 15, 2009). All comments from GVEA have been addressed in the RTC document. Three GVEA comments of note pertaining to the general approach used in the cost analysis are discussed below.

- GVEA commented that Section IV.D.4.k of the BART rule (40 CFR 51, Appendix Y) provides for the consideration of a unit's *remaining useful life* when amortizing control system costs. GVEA indicated the remaining useful lifetime of Healy 1 to be approximately 15 years from current (2009). As such, GVEA requested the Department approve a revised SCR cost analysis they submitted during the comment period that used an 8-year cost amortization period determined as follows: Alaska regional haze implementation plan (SIP) timeline would likely require BART retrofit controls (and emission limits) to be installed by

2016, resulting in an 8-year remaining useful life (and cost amortization period) for Healy 1 (i.e., 2009 + 15 = 2024; 2024 - 2016 = 8 years). As indicated in the RTC document, the Department agrees that the referenced BART rule citation supports GVEA's use of the 8-year amortization period in their cost analysis. It is nonetheless noted that the site-specific SCR cost evaluation performed by Fuel Tech (see Sections 5-1 and 6-1) has resulted in SCR being determined as cost ineffective, irrespective of the amortization period used in the cost analysis.

- GVEA provided the 8-year cost analysis described above for the SCR option only. As such, the Department requested Enviroplan to re-compute the GVEA cost analyses for all remaining NO_x and SO_2 retrofit options using an 8-year capital cost amortization period (O&M costs are not affected by amortization, and these costs as previously provided by GVEA remain unchanged unless otherwise noted herein). The costs presented in following Sections 6-1 and 6-2 are revised accordingly. The revisions do not escalate present (2009) costs to 2016 costs. Non-escalated current costs were applied herein to simplify the analysis since cost comparison metrics were not escalated by GVEA in a similar manner.
- The NPS commented that the GVEA BART cost analysis should have utilized the OAQPS Control Cost Manual as per the BART Guidelines. As indicated in the RTC document, while the BART Guideline (40 CFR 51, Appendix Y, Section IV.D.4.a.5) does recommend use of the Control Cost Manual for cost consistency purposes "where possible", the Guideline does not exclusively require use of this document. Since the EPA's CUECost tool has been developed for cost estimation of air pollution control systems installed on coal-fired utility emission units, Enviroplan believes CUECost, as reflected in the GVEA cost analyses, to be suitable for the BART cost analysis. CUECost has been applied by other BART affected source owners/operators (see, for example footnote 4).

One potential metric that can be used as a starting point in terms of deciding the acceptability of the cost effectiveness of a potential BART control is the BART rule itself. In its June 24, 2005 Regional Haze Final Rule Preamble, EPA estimated ranges of cost effectiveness, as shown below, that were used to establish presumptive NO_x and SO_2 emission limits for EGUs. It is noted that the Healy 1 unit does not fall in the category listed in 40 CFR 51, Appendix Y as a unit subject to the presumptive emission limits. Further, the costs presented below are not considered as ceiling values never to be exceeded, and they must be considered in combination with the findings of the other steps of the BART determination process. Nevertheless, these values are considered as a point of reference in this cost effectiveness evaluation process.

- \$400 to \$2000 per ton of SO_2 removed.
- \$100 to \$1500 per ton of NO_x removed.

6.1 NO_x Control Technologies

Table 6-1 below provides a summary of the annual operating costs, the total tons of NO_x removed, and the average annual cost effectiveness for each NO_x retrofit control system. The information presented in Table 6-1 is reflective of costing provided by GVEA (applicant), as revised by Enviroplan to reflect an 8-year capital cost amortization period in accordance with 40 CFR 51, Appendix Y, Section IV.D.4.k, as discussed in the previous section.

[4] State of Oregon, Department of Environmental Quality, "Agenda Item J, Action Item: 2008 Oregon Regional Haze Plan and new controls for PGE Boardman coal-fired power plant proposed rulemaking", Attachment B, Summary of Comments and DEQ Response, June 18-19, 2009 EQC Meeting.

Table 6-1: NO_x Cost Effectiveness Summary for Healy 1

Remaining Useful Life	Cost Item	Optimize Existing LNB w/OFA	SNCR	ROFA	ROFA/ Rotamix	SCR(1)
8 Years(2)	Total Installed Capital Cost	$20,000 ($1/kw)	$2,538,900 ($102/kw)	$4,572,000 ($183/kw)	$6,912,000 ($276/kw)	$21,860,887 ($874/kw)
	Capital(3) Recovery	$3,480	$441,794	$795,574	$1,202,757	$3,804,013
	Fixed and Variable O&M Costs	$0	$122,191	$138,852	$287,309	$1,125,172
	Total Annualized Cost	$3,480	$563,985	$934,426	$1,490,066	$4,929,185
	Tons NO_x (4) Removed	74	134	194	253	313
	Average Cost Effectiveness ($/ton)	$47	$4,208	$4,827	$5,886	$15,762
	Incremental Cost Effectiveness ($/ton)	$47	$9,409	$6,219	$9,328	$57,734

Notes:
(1) Based on the 0.28 lb/MMBtu scenario as presented in the June 15, 2009 letter to ADEC from Kristen DuBois of GVEA.
(2) Based 40 CFR 51, Appendix Y, Section IV.D.4.k (i.e., a 15-year remaining useful lifetime (from 2009) for Healy 1 specified by GVEA and an expected AK regional haze SIP emission limit and pollution control install applicability date of 2016).
(3) Based on a capital recovery factor of 0.17401 for 8 years at 8%.
(4) Relative to baseline emission rate of 0.28 lb/MMBtu.

The following is noted with respect to the results of Table 6-1. The April 27, 2009 proposed BART Findings Report recommended installation of an SCR system as BART NO_x control for Healy 1. This recommendation was based on a review of all related information submitted to the Department, largely from GVEA; and the requirements of the federal and state BART rule. Comments pertaining to proposed BART were received from GVEA during the related 35-day notice period (May 12, 2009 - June 15, 2009). Of note, GVEA disagreed with the SCR proposed BART finding and Enviroplan's cost analysis found in Section 6.1 of the April 2009 Findings Report (which was based on the Control Cost Manual). As such, GVEA decided to contract a SCR application consulting company to conduct an on-site evaluation and develop a refined cost estimate for a retrofit SCR system for Healy 1. The consultant, Fuel Tech, Inc., conducted the evaluation on May 27, 2009. Fuel Tech provided a project report to GVEA on June 10, 2009 (this was included with GVEA's June 15, 2009 proposed BART comments). Fuel Tech estimated the site-specific capital cost for the SCR retrofit project at $13,300,000. Related costs for project management, engineering, equipment relocation, demolition, new induced draft fan and motor, duct stiffening, and other onsite modifications; and relevant operation and maintenance (O&M) costs, were estimated by GVEA per Fuel Tech recommendations. Since the BART Guideline supports the use of site-specific design and other conditions that affect the cost of a particular BART analysis, GVEA revised their SCR cost evaluation using the Fuel Tech study data. As discussed in the RTC document, Enviroplan reviewed the information and generally agreed with the analysis; however, a minor revision was made to eliminate double-counting of certain O&M costs, which was acknowledged by GVEA on August 27, 2009. Also, current (2009) cost estimates were used instead of GVEA escalated 2016 cost estimates, as explained in the preceding section of this report.

The most effective NO_x retrofit control system, in terms of reduced emissions, that is considered to be technically feasible for Healy 1 includes combustion controls (LNB/OFA) with post-combustion SCR. This combination of controls should be capable of achieving the lowest controlled NO_x emission rate on a continuous basis. The effectiveness of the SCR system is dependent on several site-specific system variables, including the size of the SCR, catalyst layers, NH_3/NO_x stoichiometric ratio, NH_3 slip, and catalyst deactivation rate; however, GVEA has indicated an emission limit of 0.07 lb NO_x/MMBtu should be achievable for Unit 1. This retrofit option is relatively expensive and reflects the most costly option of all retrofit options considered (total annualized cost of almost $5 million).

The least expensive NO_x retrofit control system that is considered technically feasible for Healy 1 is the optimization of the current LNB/OFA system. This control option is expected to achieve an average control efficiency improvement of approximately 18% versus the current existing configuration at a relatively inexpensive annualized cost (8-year amortization) of approximately $3,480. However, while optimization is considered as a potential retrofit option in their analysis, GVEA has expressed their uncertainty whether optimization of the existing LNB+OFA system can actually achieve the NO_x reduction assumed by GVEA for this option.

In terms of assessing the cost effectiveness and economic viability of the SCR option, the April 2009 Findings Report referenced a compilation of SCR retrofit cost analyses for BART eligible boilers prepared in January 2009 by the NPS[5]. The NPS study results estimated SCR retrofit capital investment costs in the range of $80/kW to $270/kW. The site-specific SCR cost ($/kW) shown in Table 6-1 is more than three times greater than the upper bound of this cost range.

6.1.1 Cost of Compliance

The average annual cost effectiveness for NO_x control on Healy 1, based on 8-year amortization of capital costs, ranges from $47/ton for the optimization of the current LNB+OFA system to over $15,700 for existing combustion controls plus SCR on Healy 1; with a related total capital investment ranging from $1/kW (optimization) to about $870/kW for SCR.

With the exception of optimization, the annual cost effectiveness of each retrofit option exceeds EPA's presumptive EGU level for BART ($1500/ton), as presented earlier in this Section 6. While the presumptive cost is exceeded by at least a factor of two, as already indicated herein, the presumptive costing information is not a ceiling value; instead, it is a guideline value that must be considered in combination with the findings of the other BART analyses (steps).

6.1.2 Energy Impact

Evaluation of the energy factor indicates that there is no significant energy penalty associated with the optimization of the current LNB and OFA system. However, operation of an SCR system has certain collateral environmental consequences. In order to maintain low NO_x emissions some excess ammonia will pass through the SCR. Ammonia slip will increase with lower NO_x emission limits, and will also tend to increase as the catalyst becomes deactivated. The application of an SCR system would also consume power and reduce efficiency, thereby decreasing energy available to consumers. The additional electrical demand will consume

[5] Email forwarded Don Shepherd, NPS, to various recipients, entitled "SCR Capabilities and Costs", dated January 9, 2009.

almost 0.5 percent of the total generating capacity of Healy Unit 1. These energy impacts are included in the operational costs as part of the economic impact analysis.

6.1.3 Non-Air Quality Environmental Impacts

Evaluation of the non-air quality environmental impacts indicates that there are no non-air quality related impacts associated with the optimization of the current LNB and OFA system. However, SCR requires some form of ammonia (NH_3) source for operation. This can be stored in liquid, solid or gas, and processed on site for use. Depending on quantities stored there will be risk management requirements associated with ammonia storage. Also, production of ammonia primarily uses a finite resource (natural gas), so use of ammonia could have long term consequences on fossil fuel supplies. In addition, SCR may cause enough ammonia accumulation in ash to make the ash not usable for cement and other beneficial uses. Currently, the plant sells much of its ash for such beneficial uses. If the ash is contaminated by ammonia, there will be associated environmental impacts in the form of additional land use requirements. Since both SNCR and Mobotec Rotamix® also rely on the use of a urea or ammonia reagent, use of these systems may similarly result in excess ammonia emissions (slip); ammonia storage and management issues; and possible non-salability of ash and the need to landfill the ash in a regulated solid waste facility.

6.2 SO_2 Control Technologies

Table 6-2 below provides a summary of the expected annual operating costs, the total tons of SO_2 removed, and the average annual cost effectiveness for each SO_2 retrofit control system. The information presented in Table 6-2 is reflective of costing provided by GVEA, as revised by Enviroplan to reflect an 8-year capital cost amortization period in accordance with 40 CFR 51, Appendix Y, Section IV.D.4.k, as discussed in Section 6 above.

Table 6-2: SO_2 Cost Effectiveness Summary for Healy 1

Remaining Useful Life	Cost Item	Optimization of Dry Sorbent Injection System	Semi-Dry FGD (Lime Spray Dryer)	Wet Limestone FGD
8 Years(1)	Total Installed Capital Cost	$2,000,000 ($80/kw)	$8,357,143 ($334/kw)	$15,042,857 ($602/kw)
	Capital Recovery(2)	$348,020	$1,454,227	$2,617,608
	Fixed and Variable O&M Costs	$405,782(3)	$631,511	$901,654
	Total Annualized Cost	$753,802	$2,085,738	$3,519,262
	Tons SO_2 Removed(4)	179	223	343
	Average Cost Effectiveness(5) ($/ton)	$4,218	$9,337	$10,275
	Incremental Cost Effectiveness ($/ton)	$4,218	$29,813	$12,033

Notes:

(1) Based 40 CFR 51, Appendix Y, Section IV.D.4.k (i.e., a 15-year remaining useful lifetime (from 2009) for Healy 1 specified by GVEA and an expected AK regional haze SIP emission limit and pollution control install applicability date of 2016).
(2) Based on a capital recovery factor of 0.17401 for 8 years at 8%.
(3) Fixed and variable O&M costs based on Enviroplan's estimates of the additional reagent and other related costs required to achieve 70% control (relative to the existing 50% control baseline), using a coal having an uncontrolled SO_2 emission rate of 0.60 lb/MMBtu.
(4) Relative to baseline emission rate of 0.30 lb/MMBtu.
(5) Annual and incremental costs for the dry sorbent injection optimization control scenario (70% control) were calculated relative to the existing (baseline) dry sorbent control scenario (50% control). Average costs for other options calculated relative to the existing controlled baseline.

The following is noted with respect to Table 6-1. The April 27, 2009 proposed BART Findings Report included optimizing the existing dry FGD system (i.e., increasing the sodium bicarbonate sorbent feed rate) as a SO_2 retrofit option for Healy 1. Section 6.2 of the April 2009 report discussed the cost analysis for that option, which was revised by GVEA on March 18, 2009. In summary, the optimization scenario reflects increasing sorbent injection from 370 lb/hr (current baseline) to a sorbent usage rate that equates to a continuous 70 percent SO_2 reduction relative to an uncontrolled emission rate (i.e., additional 40 percent reduction relative to the current baseline rate). GVEA estimated the optimized sorbent feed rate to be between 700 lb/hr to 1400 lb/hr; and the related sorbent cost to be \$0.5 to \$1.0 million (\$750,000 average was assumed for BART economic evaluation purposes). Comments on this analysis were received from the Sierra Club during the related 35-day notice period (May 12, 2009 - June 15, 2009). As detailed in the RTC document, the Sierra Club noted a potential inaccuracy in the sorbent increase estimate based on relevant information specified in a Department of Energy document[6]. In response to this comment, Enviroplan requested clarifying information (through the Department) from GVEA on August 17, 2009; received the requested information on August 27, 2009; and revised both the Sierra Club/GVEA additional sorbent usage estimate and the related retrofit option costs. The details of such are contained in the RTC document, and the results are reflected in Table 6-2.

6.2.1 Cost of Compliance

The annual average cost effectiveness for SO_2 control on Healy 1, based on 8-year amortization of capital costs, is \$4,218/ton for the optimized existing FGD option and greater than \$9,000/ton for both the wet FGD system and lime spray dryer options. EPA estimated that for a majority of BART eligible units greater than 200 MW, cost of control systems used to meet the presumptive SO_2 emission limits is \$400 to \$2,000 per ton of SO_2 removed (see 70 FR 39133). Therefore, for two of the options the average effectiveness of SO_2 removal at Healy 1 is more than quadruple the upper bound cost effectiveness calculated by EPA for SO_2 control on large EGUs. For existing FGD optimization the presumptive cost, which is a guideline value and not a ceiling value, is exceeded by at least a factor of two. The wet limestone FGD system control option is expected to achieve an average control efficiency of approximately 77% from current controlled baseline at an annualized cost of over \$3.5 million; the lime spray dryer control option is expected to achieve 50% from current baseline at an annualized cost of almost \$2.1 million; and optimizing the existing FGD system is expected to achieve 40% from baseline at an annualized cost of about \$750,000.

6.2.2 Energy Impact

Evaluation of the energy factor indicates that the installation of a new wet limestone FGD system would require additional power. Auxiliary power is required for material handling, reactant preparation, pumps, mixers, and to overcome significant pressure drops through the reaction vessels. Based on the economic analysis performed, the auxiliary power requirement for wet FGD control system is approximately 0.94% of the gross energy output of the generating unit. Healy 1 has a gross rating of 25 MW; therefore, auxiliary power requirements for FGD control system would be approximately 240 kilowatts (kW). Energy impacts associated with each control technology were included in the BART economic impact evaluation as an auxiliary power cost.

[6] U.S. Department of Energy, "*Integrated Dry NO_x/SO_2 Emissions Control System Sodium-Based Dry Sorbent Injection Test Report"*, DOE Contract Number DE-FC22-91 PC90550, Final Report April 1997.

6.2.3 Non-Air Quality Environmental Impacts

Evaluation of the non-air quality environmental impacts indicates that the installation of a new wet limestone FGD system will also result in the storage of new chemicals onsite and a new waste stream for the facility. The exit flue gas stack temperature with both of these technologies will be less than the current operation, thus flue gas buoyancy will be decreased. In addition, saturated flue gas would significantly increase the probability of creating fog during the summer and ice fog during the winter, in the area surrounding the plant.

6.3 Economic Impacts – Rate Payer Analysis

The April 27, 2009 proposed BART Findings Report, Section 6.3, included an analysis of the potential costs to GVEA residential rate payers for the SCR (NO_x) and increased sorbent injection (SO_2) BART control scenarios for Healy 1. Comments pertaining to proposed BART were received from GVEA and the NPS during the related 35-day notice period (May 12, 2009 - June 15, 2009). Of note, the NPS disagreed with the analysis and suggested it was not supported by the BART rule; and GVEA disagreed with the resultant percent increase in costs to rate payers should SCR and FGD optimization be required for installation. As detailed in the RTC document, and as reflected below, 40 CFR 51, Appendix Y, Section IV.E.3 supports the rate payer cost consideration. As such, this report has revised the rate payer cost analysis to reflect the capital cost revisions pertaining to the existing FGD optimization option (see discussion in Section 6.2 above). Further, the prior rate payer cost analysis which considered SCR for NOx control has been replaced with the SNCR option (see conclusions section later in this document). The RTC document provides further detail on these changes; however, the revised results are reflected in Tables 6-3-3 and 6-3-4 below.

The above notwithstanding, during February 2009 conversations with the Department, GVEA requested that rate payer cost considerations be included as part of the cost of compliance with the BART rule. Rate payer cost analysis information was not provided, nor considered, by GVEA in their July 2008 and January 2009 BART analysis submittals. However, 40 CFR 51, Appendix Y, Section IV.D, Step 4, does allow for unusual circumstances that exist for a source that might lead to unreasonable cost-effectiveness estimates. Further, 40 CFR 51, Appendix Y, Section IV.E provides for summarization of costs of compliance using cost-effective measures relevant to the source. As such, the Department agreed to such considerations and GVEA provided rate payer cost data and analyses on March 18, 24 and 30, 2009.

The BART rule provides that the energy impacts analysis may consider whether a particular control alternative would result in a significant economic disruption within the area or region of the affected source. As such, the unique geographic and economic characteristics affecting the business community within Alaska, including power producers, justify that the potential control costs consider the economic impact on each customer, expressed in units of cost per kilowatt-hour. Below is a list of attributes that describe the communities served by GVEA.

- The community is not connected to a nationwide or outside electric grid or connected to other utilities;
- The community does not have access to large scale alternative power generation options (continuous hydro-power, geothermal energy, and wind energy);

- The stationary source is owned by a small publicly owned non-profit association and electricity rates would be adjusted to account for any increased facility costs; and
- The stationary source is located in a remote area, which is not accessible year round for economical supply of fuel and reagent.

The GVEA rate payer base is small relative to typical electric utilities within the continental United States. GVEA residential customers paid $0.17705/kWh in the year 2008. As established by the Department of Energy, the "Representative Average Unit Cost" of electricity for a residential user is $0.0973/kWh. So, a residential customer of GVEA pays 180 percent of the national average. Given this relatively high cost to GVEA residential rate payers, the costs of BART control systems have been evaluated by GVEA on a per rate payer basis. The following presents a summary of Enviroplan's April 27, 2009 findings associated with our review of GVEA's rate payer analysis that was based on the SCR (NO_x) and increased FGD sorbent injection (SO_2) BART control options:

- GVEA rate payer analysis submitted on March 18, 2009:
  - The rate payer analysis reflected combined costs for NOx and SO_2 control systems, and it did not include individual control system cost analyses
  - Rate payer analyses were presented for both GVEA (i.e., entire plant) and Healy Unit 1, based on budget and electric output projections for 2009
  - Rate payer analysis based on non-fuel expenses only (did not include fuel costs)
  - Results showed an incremental rate payer increase due to BART controls of:
    - 3.3% when compared to annual average rate payer costs for entire plant
    - 36% when compared to annual average rate payer cost for Healy Unit 1 alone
  - GVEA specified a 25% increase in energy charge to rate payers since 2002
  - GVEA specified the 25% increase does not include rising fuel costs which are passed directly to their customers
  - GVEA expects in 2010 another 5.6% increase in energy charge, for a total increase since 2002 of 30.6%
  - GVEA notes the national average rate payer cost as of November 2008 to be 9.73 cents/kW-hr (average Alaska cost for November 2008 was 14.28 cents/kW-hr), while GVEA's rate payer cost for November 2008 was 19.502 cents/kW-hr
  - GVEA qualitatively indicates the rate payer costs to be proportionally higher than for utilities with a large rate base (GVEA residential rate base is 36,860 customers)
- Supplemental GVEA rate payer analysis information submitted on March 29, 2009:
  - Rate payer analysis provided for individual NOx and SO_2 control systems, with findings of:
    - 1.86% rate payer increase for SO_2 control system (increased sorbent injection)
    - 1.41% rate payer increase for NO_x control system (SCR)
  - GVEA provided 2008 annual average residential customer energy charge of 17.705 cents/kW-hr
- Enviroplan reviewed GVEA increased rate payer estimates and determined different percent increases to the rate payers as follows:
  - 0.70% rate payer increase for SO_2 control system
  - 0.43% rate payer increase for NO_x control system

- Differences between Enviroplan and GVEA findings due to:
    - Enviroplan revised (reduced) GVEA's March 2009 control system capital cost information
    - Enviroplan used 2008 annual average residential rate payer cost, as provided by GVEA (17.705 cents/kW-hr) as the basis for determining incremental increases to rate payers, rather than using the 2009 nonfuel costs as used by GVEA
    - Enviroplan only considered incremental rate payer cost increases relative to operating GVEA (i.e., the entire plant), and, no consideration is given to incremental cost increases relative to only operating Healy Unit 1

Tables 6-3-1 and 6-3-2 present GVEA's rate payer cost analysis results from the April 27, 2009 findings report.

Table 6-3-1: GVEA Estimated Operating Expenses for the SCR NOx Control Option

2009 Non-Fuel Cost ($)	Post Control Non-Fuel Cost ($)	2009 Anticipated Total Sales (kWh)	2009 Non-Fuel Cost per kWh ($/kWh)	Post Control Non-Fuel Cost pe kWh ($/kWh)	Percent Increase (%)
89,299,216	90,562,467	1,380,383,090	0.06469	0.06561	1.41

Notes:
2009 non-fuel cost per kWh ($/kWh): $89,299,216 / 1,380,383,090 kWh = $0.06469/kWh
Post controls non-fuel cost per kWh ($/kWh): $90,562,467 / 1,380,383,090 kWh = $0.06561/kWh

Table 6-3-2: GVEA Estimated Operating Expenses for the FGD Optimization SO_2 Control Option

2009 Non-Fuel Cost ($)	Post Control Non-Fuel Cost ($)	2009 Anticipated Total Sales (kWh)	2009 Non-Fuel Cost per kWh ($/kWh)	Post Control Non-Fuel Cost pe kWh ($/kWh)	Percent Increase (%)
89,299,216	90,955,806	1,380,383,090	0.06469	0.06589	1.86

Notes:
2009 non-fuel cost per kWh ($/kWh): $89,299,216 / 1,380,383,090 kWh = $0.06469/kWh
Post controls non-fuel cost per kWh ($/kWh): $90,955,806 / 1,380,383,090 kWh = $0.06589/kWh

As discussed in the RTC document, Enviroplan has revised the April 27, 2009 GVEA rate payer cost estimates presented in the preceding tables. The revision is based, in part, on the control system cost revisions discussed in Section 6. Further, the GVEA analyses shown above do not include fuel costs. Enviroplan understands that fuel costs are highly variable; however, this is a direct cost born by each ratepayer and its exclusion could result in a bias (overstatement) in the percent increase computed in this analysis. As such, Enviroplan utilized the actual 2008 annual average ratepayer cost provided by GVEA as the baseline for determining percent ratepayer increases due to the BART control systems. Tables 6-3-3 and 6-3-4 present Enviroplan's estimated rate payer cost increases for SNCR (in place of SCR that was considered in the April 27, 2009 report) and increased sorbent injection.

Table 6-3-3: Enviroplan Estimate of Healy Plant Ratepayer Expense Due to Implementation of the SNCR NOx Control Option

Parameter	Cost
Annualized Total Cost [1]	$563,985
Cost Associated w/SNCR ($/kWh) [2]	$0.00041
Avg Ratepayer Cost for 2008 ($/kWh) [3]	$0.17705
Percent Increase due to SNCR	0.23%
@500kW-hr/month	$0.21/month and $2.46/year
@1,000kW-hr/month	$0.41/month and $4.92/year

Table Notes:
1. Reflects depreciation over 8 years at an 8 percent interest rate (i.e., 0.17410 capital recovery factor).
2. Reflects control cost relative to total plant sales (i.e,. total annualized control system cost/2009 anticipated total sales (kWh)).
3. Provided by GVEA.

Table 6-3-4: Enviroplan Estimate of Healy Plant Ratepayer Expense Due to Implementation of FGD Optimization SO_2 Control Option

Parameter	Cost
Annualized Total Cost [1]	$639,442
Cost Associated w/FGD Optimization ($/kWh) [2]	$0.00046
Avg Ratepayer Cost for 2008 ($/kWh) [3]	$0.17705
Increase due to Injection System	0.26%
@500kW-hr/month	$0.23/month and $2.76/year
@1,000kW-hr/month	$0.46/month and $5.52/year

Table Notes:
1. Reflects depreciation over 15 years at an 8 percent interest rate (i.e., 0.11683 capital recovery factor).
2. Reflects control cost relative to total plant sales (i.e,. total annualized control system cost/2009 anticipated total sales (kWh)).
3. Provided by GVEA.

While the rate payer cost analysis presented above is determined in reference to the BART rule, the Department has considered similar rate payer cost impacts for major source (PSD sources) control technology evaluations (i.e., BACT). For the two tables shown immediately above, the similar approach to determining rate payer costs as found in the Technical Analysis Report (TAR) to Permit AQ0215CPT02 was applied.

Based on the information tabulated in Tables 6-3-3 and 6-3-4, use of the GVEA 2008 ratepayer cost, which includes fuel and non-fuel charges, results in a potential ratepayer increase of 0.23% and 0.26% for the SO_2 and NO_x control systems, respectively. When considering these BART controls for GVEA, the total incremental increase above the 2008 average rate payer cost is estimated to be 0.49 percent. For a family that uses 500 kWh/month, this would equate to a combined cost increase of about $5.20/year; and about $10.40/year for a family that uses 1,000 kWh/month.

Enviroplan acknowledges the incremental costs associated with the individual installations of these control options; however, we do not believe these costs to be prohibitive in terms of the assessing the viability of either emissions reduction system. It is noted that the increase in the cost to a residential rate payer is presented on a per control option basis (i.e., does not reflect the total combined costs of both the NO_x and SO_2 control system options). The BART rule requirements are specific in that the BART emission limitations (and possible retrofit control technologies) are to be determined on a per visibility impairing pollutant (VIP) basis, and not on a combined VIP basis.

7. VISIBILITY IMPACTS EVALUATION (Step 5)

Pursuant to 40 CFR 51, Appendix Y and 18 AAC 50.260, the BART determination must include an evaluation of the impacts associated with the installation of various control options regarding potential visibility benefits in Class I areas. As provided by 18 AAC 50.260(h)(3)(A), GVEA opted to conduct their visibility modeling analysis in accordance with the modeling protocol developed by the Western Regional Air Partners (WRAP) - Regional Modeling Center (RMC).

The visibility modeling analysis conducted by GVEA and their consultant, CH2M Hill, is intended to comply with 40 CFR 51, Appendix Y, Section IV.D - Step 5, "*How should I determine visibility impacts in the BART determination?.*" GVEA conducted the analysis to support their control analysis and proposed BART determinations. Since GVEA currently uses a high efficiency baghouse for particulate control, which is considered BART for this pollutant/emission unit, no specific visibility modeling analyses are required for particulates pursuant to 40 CFR 51, Appendix Y, Section IV.D - Step 1.9. For the feasible NO_x and SO_2 retrofit control technology options presented in Section 4, GVEA estimated the visibility impacts according to the following sequence:

- Model pre-control (i.e., existing baseline) emissions
- Model individual post-control emissions scenarios
- Determine degree of visibility improvement
- Factor visibility modeling results into BART "five-step" evaluation, including a visibility cost effectiveness metric expressed as cost of control option per deciview improvement ($/dV)

The following sections provide the findings associated with the methods used by GVEA to evaluate the visibility impacts at the DNPP Class I area and the potential visibility improvements associated with the retrofit technologies evaluated by GVEA.

7.1 CALPUFF Modeling Approach

GVEA used the CALPUFF modeling system to estimate their visibility impacts. Their approach is described in Section 4 of the GVEA January 2009 BART control analysis report. However, Enviroplan also relied on the following information, as needed, as part of the review:

- July 2008 BART analysis report and companion CALPUFF modeling files prepared by CH2M Hill, and submitted by GVEA on July 28, 2008;
- October 16, 2008 letter from Enviroplan to the Department requesting clarification and additional information pertaining to the July 2008 submittal (which the Department forwarded to GVEA and CH2M Hill on October 16, 2008);
- November 11, 2008 submittal by GVEA of CH2M Hill responses to the October 16, 2008 Enviroplan letter, along with the revised CALPUFF modeling files submitted on behalf of GVEA by CH2M Hill;
- December 4, 2008 letter from Enviroplan to the Department requesting further clarification and additional information pertaining to the November 11, 2008 submittal (which the Department forwarded to GVEA and CH2M Hill on December 4, 2008);

- December 11, 2008: Teleconference between the Department Enviroplan, CH2M Hill, GVEA, to discuss the December 4, 2008 Enviroplan letter and a draft response provided by GVEA on December 10, 2008;
- Final revised January 2009 BART analysis report prepared by CH2M Hill; and a companion "GVEA Healy BART Response to 12/04/08 Comments from Enviroplan" document, submitted by GVEA on January 2, 2009. No further changes were made to the November, 2008 CALPUFF modeling files.
- Teleconferences between the Department, GVEA, CH2M Hill and Enviroplan on February 25 and 27, 2009 and March 2, 2009; and related BART study information submitted on March 18, 2009 with additional clarifying information submitted on March 24 and 30, 2009. No further changes were made to the November, 2008 CALPUFF modeling files.

In addition to the above, the Department received comment on the April 27, 2009 proposed BART Findings Report during the related 35-day public notice period (May 12, 2009 - June 15, 2009). Of note, the NPS disagreed with several aspects of the visibility modeling analysis. While all comments from the NPS (and all other commenter's) have been addressed in the RTC document, the following clarifications are provided in relation to the visibility modeling and the NPS comments:

- The GVEA visibility modeling analysis did not include a GEP stack height analysis to assess the potential for aerodynamic building downwash of affected source stacks and plumes. This approach is consistent with the WRAP modeling protocol which was followed by GVEA to conduct their visibility impact analysis.
- The GVEA visibility modeling analysis did not include a receptor-by-receptor impact evaluation at DNPP for pre- and post-control options. The BART Guideline does not require such an analysis. Instead, pursuant to the Guideline, ranked delta-deciview visibility impacts were determined by GVEA using CALPOST for the pre- and post-control scenarios. While the BART Guideline requires a comparison of the 98^{th} percent days for the pre- and post-control scenarios, GVEA conducted the required comparative assessment using maximum delta-deciview values (pre- versus post-control) since only one year of meteorological data was used in the analysis. This is approach is consistent with Department BART modeling requirements.
- GVEA modeled the Healy 1 total PM_{10} emissions without speciation, with total PM_{10} assumed equal to $PM_{2.5}$. The Department has acknowledged the use of unspeciated PM_{10} emissions data in the BART visibility modeling[7]; therefore, GVEA's use of total PM_{10} (as $PM_{2.5}$) as input to the CALPUFF modeling is consistent with the WRAP protocol, as adopted by the Department, and the WRAP CALPUFF modeling input files.

In addition to the above, comments were received by GVEA during the 35-day notice period that results in a change to the Healy 1 baseline NOx emission rate from 0.25 to 0.28 lb/MMBtu (see related discussion in Section 5.1). This baseline emission rate reflects a 30-day rolling emission rate used for the cost analysis, and it does not affect the peak 24-hour NOx emission rate used in the visibility impact modeling.

[7]*Summary of WRAP RMC BART Modeling for Alaska, Draft #7, dated April 6, 2007.*

Finally, GVEA submitted a request for an informal review on February 24, 2010 pertaining to specific BART determination findings, including the correction to certain findings as necessary (e.g., see Section 2 herein). The Department's decisions relating to GVEA's review request are incorporated into this final BART determination as necessary.

The following discussion presents findings related to the GVEA CALPUFF visibility modeling analysis.

BART-Eligible Source Emission Rates and Stack Parameters

Section 4.0 of the final GVEA BART study report presents the emissions inventory data used in the visibility modeling analysis. The following summarizes the information used in the CALPUFF input files, and any findings relating to review of this information:

- Review of the CALPUFF input files provided by GVEA (November 2008) indicates that the stack parameters and emission rates shown in the final report Table 4-3 and 4-4 have been used in the CALPUFF visibility modeling.
- The NO_x, SO_2 and PM_{10} emission rates used in the CALPUFF modeling for Auxiliary Boiler #1 are consistent with the emission rates used by WRAP. However, as discussed in both Section 2 and Appendix B herein, the Department determined the boiler's modeled NO_x and SO_2 emission rates were inadvertently understated by three orders of magnitude. Enviroplan re-evaluated the visibility impacts attributable to the boiler using the corrected emission rates (see Appendix B).
- The PM_{10} emission rate used in the modeling analysis for Unit 1 is based on a 2004 stack test. It is noted that a review of the WRAP-RMC CALPUFF input files for Unit 1 indicated that no particulate matter emission rate was used by WRAP for this unit. This notwithstanding, GVEA/CH2M Hill has correctly used the stated PM_{10} emission rate in their July 2008 visibility modeling, and their resubmitted November 11, 2008 visibility modeling.
- Auxiliary Boiler #1 stack exit parameters used in the CALPUFF modeling are consistent with the same parameters used in the WRAP modeling. The modeled stack parameters used by GVEA for Unit 1 reflect more accurate information based on a reevaluation of the physical characteristics of the stack, as indicated by GVEA in their November 11, 2008 response.
- For each BART eligible source, all PM_{10} emitted has been assumed as $PM_{2.5}$, which is consistent with the WRAP modeling.
- Stack parameters for each control scenario have been provided by GVEA that reflect the anticipated changes associated with installation of each control technology alternative being evaluated.
- The NO_x and SO_2 emission rates used in the CALPUFF modeling for Unit 1 are based on continuous emissions monitoring (CEM) data recorded by GVEA for the period May 1, 2007 through April 30, 2008. 40 CFR 51, Appendix Y recommends that the pre-control emissions (i.e., existing configuration) be modeled using "*the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled*". Calendar year 2002 is the meteorological period modeled by WRAP. CH2M Hill clarified on 11/11/08 that GVEA did not have readily available emissions information for 2002 due to a recent CEMs system upgrade; therefore, the most recent one-year period (5/1/07 - 4/20/08) was used as a

surrogate data period. Section 4.3.3 of the GVEA final report indicates the CEM data represents a realistic depiction of anticipated annual emissions for the unit. Due to the lack of 2002 actual emissions information, the current CEM data is - an acceptable surrogate data set for this analysis.

- GVEA modeled their current (existing) control configuration using two emission rate scenarios. GVEA used the "peak 24-hour" NO_x and SO_2 emission rates for their "baseline" scenario. GVEA also developed a "null" scenario wherein they used an "anticipated 24-hour" emission rate for the "controlled" pollutant (e.g., SO_2 when evaluating the existing dry FGD system), and the "peak" emission rate for the "other" pollutant (e.g., NO_x when evaluating the existing dry FGD system). The "anticipated" emission rates reflect the 24-hour emission rates averaged over a full-year of boiler operation. The 24-hour average NO_x and SO_2 emission rates for the respective "baseline" and "anticipated" configurations, expressed as hourly emission rates, are summarized below:

Scenario*	NO_x (lb/hr)	SO_2 (lb/hr)
Baseline ("peak" 24hour average emission rates)	151.0	182.2
Null ("anticipated" 24hour average emission rates)	85.0	102.0

*Both scenarios reflect existing controls, i.e., low NOx burners/over-fire air and dry sodium bicarbonate flue gas desulfurization (FGD) system

Enviroplan initially believed that GVEA used the "anticipated" emission rates to determine modeled emission rates for the other retrofit control scenarios. However, GVEA clarified during the February 25 and 27, 2009 teleconferences that the modeled "null" option was presented for informational purposes only, and that it was not used as the basis for establishing modeled emission rates for each retrofit control option. GVEA indicated that the emission rates used for each retrofit control option were based on vendor information and professional engineering judgment; and they did not multiply the retrofit control efficiencies presented in their report (e.g., Table 3-2) by the "null" 24-hour emission rates. Finally, GVEA clarified that the control efficiencies were used only for control cost determination purposes (in conjunction with "null" emission rates). This is acceptable for control cost purposes only, since 40 CFR 51, Appendix Y, Section IV.D., Step 4, suggests that a realistic depiction of anticipated annual emissions be used for cost estimation purposes.

Based on the above, Enviroplan has determined that the NO_x and SO_2 emission rates used in the visibility modeling analysis for each retrofit scenario are correct; and the modeling results for the "null" configuration have been ignored. Likewise, the visibility modeling summary results presented in Tables 4-7 and 5-1 of the GVEA 2009 study report are correct. Findings associated with our review of these results tables are presented at the end of this section.

CALMET Modeling Procedures

The CALMET modeling methods and input file have been compared for consistency with the recommendations of the WRAP protocol. GVEA's CALMET modeling approach is summarized below:

- CALMET version 6.211, level 060411;

- CALMET modeling performed for one year (2002) as recommended in the protocol, using scripts and inputs to recreate the CALMET output for the study;
- 15-km resolution 2002 MM5 data taken from the WRAP website (http://pah.cert.ucr.edu/aqm/308/bart/calpuff/calmm5/ak/2002/); and
- GVEA summarized the following information in their final report, which has been compared to the WRAP protocol and it was found to be consistent:
  - CALMET input parameters and options used by GVEA, as summarized in final report Table 4-1;
  - the meteorological surface stations, as specified in Table 4-2; and
  - the vertical layer resolution, and modeling domain extent and resolution, as specified in Section 4.2.1,

The data described by GVEA in their final study report and used in the CALMET input files are consistent with the WRAP protocol.

CALPUFF Modeling Procedures

The CALPUFF modeling methods and the related model input options selected for use in this study have been reviewed for consistency with the WRAP protocol and related BART guidance documents. Applied modeling procedures and any findings are summarized as follows:

- CALPUFF version 6.112, level 060412;
- CALPUFF modeling performed for one year (2002), consistent with WRAP modeling;
- EPA CASTNET hourly ozone data from Denali, using 40 ppb default for missing hours;
- A background ammonia concentration of 0.1 ppb (Note that this is consistent with the WRAP protocol which GVEA is using pursuant to 18 AAC 50.260(h)(3)(A), even though the U.S. Fish and Wildlife Service (FWS) has requested BART sources developing their own modeling protocols to assume a background concentration of 0.5 ppb);
- Regulatory default model options when such options are specified;
- National Park Service discrete receptor locations and elevations for DNPP (http://www2.nature.nps.gov/air/maps/Receptors/index.cfm);
- Aerodynamic building downwash not used in the modeling analysis; and
- CALPUFF computational domain consistent with the CALMET meteorological domain (NX=275, NY=325).

The data described by GVEA in their final study report and used in the CALPUFF input files are consistent with the WRAP protocol.

CALPOST Modeling Procedures

The CALPUFF post-processing methods of CALPOST and the related model input options selected for this study have been reviewed for consistency with the WRAP protocol and related

BART guidance documents. Applied modeling procedures and any findings are summarized as follows:

- CALPOST version 6.131, level 060410;
- Particle growth curve f(RH) for hygroscopic species based on EPA (2003) f(RH) tabulation;
- CALPOST default extinction efficiencies for PM fine (PMF), PM coarse (PMC), ammonium sulfate, ammonium nitrate, organic carbon (OC), and elemental carbon (EC);
- Calculation of background extinction and change to extinction using the recommended CALPOST Method 6 (MVISBK=6);
- Monthly relative humidity adjustment factors specific to the DNPP Class I area as taken from Table A-3 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003); and
- Annual average natural background aerosol concentrations as taken from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003).

The data described by GVEA in their final study report and used in the CALPOST input files are consistent with the WRAP protocol.

7.2 Visibility Modeling Results

As supported in EPA's BART rules and guidelines, when conducting visible impact modeling using only one year of meteorological data, source impacts should reflect the maximum change to the daily Haze Index (HI) as compared to a natural background, expressed in units of delta-deciviews (ΔdV). In their July 2008 report, GVEA utilized 98th percentile delta-deciview visibility predictions; however, pursuant to the BART rules, this is permissible only when modeling multiple years of meteorology (e.g., 3-years). The final January 2009 report correctly presented modeling results as maximum values (Tables 4-7 and 5-1 of the final report). Additionally, the BART rules and 18 AAC 50.260 have established 0.5 daily deciviews (dV) as the metric against which predicted visibility impacts should be compared for purposes of establishing whether a source causes or contributes to impairment of visibility.

Table 4-7 of GVEA's final report presents a summary of the highest delta-deciview visibility predictions from the one year (2002) of modeling at the DNPP Class I area for each NO_x and SO_2 emissions control scenario. Table 4-7 also presents the number of days predicted to exceed the significance level of 0.5 dV for each scenario, along with related visible cost effectiveness values (e.g., $/deciview improvement). Table 5-1 of the final report presents the change (i.e., improvement) in model prediction results when comparing "baseline" visibility predictions to the alternate control scenarios.

7.3 Visibility Monitoring Program

In addition to performing the required retrofit scenario visibility impact analysis as part of the overall BART control determination analysis, GVEA indicated in the January 2009 final report that they previously conducted a visibility monitoring program (VMP). GVEA provided in Section 1.0 of their final report a summary of the VMP, which is abbreviated below.

GVEA received a PSD permit in 1994 to expand the Healy power plant and construct the Healy Clean Coal Project (HCCP), a 50-megawatt (MW) coal-fired unit, adjacent to the existing 25 MW Unit 1. Based on a 1993 Memorandum of Agreement (MOA), Condition 26 of the permit required GVEA to develop a VMP and operate visibility monitoring equipment for the period prior to the initial startup of the HCCP through the completion of 1 full year of commercial operation of HCCP. The VMP, which was public noticed and approved by EPA, ADEC and the National Park Service (NPS), had the objective of collecting sufficient visual and measurement data to:

1. Provide reasonable assurance that NO_x, SO_2, and particle emissions from the HCCP and Healy Unit 1 sources were not adversely impairing visibility within the DNPP Class I area; and

2. Evaluate any trained NPS observer's reports of visibility impairment for their potential attribution to NO_x, SO_2, and particle emissions from operations of HCCP and Unit 1.

Under the VMP, photographic and air quality instrumentation was established at three monitoring stations, i.e., Garner Hill site overlooking the plant; the DNPP visitor's center, and the Bison Gulch ambient air monitoring station at the Park boundary. Continuous time-lapse video of Healy was taken at Garner Hill and Nenana Valley north of the DNPP Visitor Access Center. Measurements of meteorological data, SO_2 concentrations, and nephalometer readings of light scattering by sulfate particles were taken at Bison Gulch for use in estimating the contribution of the SO_2 emissions from the Healy Power Plant (Healy 1 and HCCP) to light scattering by particles within DNPP.

The VMP commenced in late December 1997, just prior to HCCP beginning its first year of the demonstration period. During the VMP time period, Healy 1 was operating with the current NO_x control configuration and the current baghouse, but the current FGD SO_2 reduction system, which was installed during 1999, was not operating. Therefore, the VMP occurred when both units were operating and Healy 1 was emitting more SO_2 than under the current configuration (with the FGD system). GVEA notes that HCCP had not been fully optimized during the VMP, resulting in emissions above normal operating conditions.

By condition of the permit, the duration of the VMP was only to occur for 2 years (1 year of demonstration operation and 1 year of commercial operation). Quarterly reports were submitted to ADEC, EPA and the NPS during the program. In 2000, the ADEC, EPA and NPS agreed the VMP could be temporarily shut down as HCCP never reached full commercial operation. HCCP has not operated since that time. GVEA indicated the results of the program demonstrated that no visibility impairment was observed by trained NPS observers while Healy 1 was operating at full load; and that actual visibility impairment at DNPP from Healy was not detectable while both units (Healy 1 and HCCP) operated. Further, GVEA indicates there were occasions during the VMP when a slight plume was visible and recorded by video, but no correlation was reached between this slight plume and any visibility issues within DNPP.

Coincident with the VMP, a three year study was conducted in which particles that cause or contribute to regional haze were measured and analyzed to determine if Healy was *contributing to regional haze. The study was funded by GVEA, managed by the NPS, and conducted by Air Resource Specialists, Inc. and the University of Alaska–Fairbanks. Results of this study are summarized in a report entitled "Final Report on the Results from the Poker Flat, Denali National Park and Preserve, and Trapper Creek CASTNET Protocol Sites, July 1998 through June 2001." Per GVEA, the report concluded that there was no specific indication that operations from the Healy Power Plant contributed to regional haze.*

GVEA concluded that the Unit 1 existing control configuration for all pollutants is BART. This conclusion is based in part on GVEA's assertion that no visibility impairment at DNPP, attributable to Healy, has been observed by trained NPS observers based on the previous visibility studies described above. GVEA further asserted during the February 27, 2009 teleconference with the Department that no visibility impairment has occurred at DNPP. This assertion was repeated in GVEA's comments to the Department on the April 27, 2009 proposed BART Findings Report. A response to this further assertion is provided later in this section, with a similar discussion provided by the Department in the RTC document.

In considering the relevance of the prior VMP in making a preliminary determination of BART for Healy 1 (and Auxiliary Boiler #1), several VMP related documents were provided by both ADEC and GVEA for consideration as part of this review/findings report. However, ADEC noted that they could *not* find evidence as to whether the VMP documents had ever been approved, or even fully reviewed by ADEC, EPA or the NPS. GVEA in their January 2009 submittal concurred, indicating that they knew of no formal correspondence from ADEC, EPA or the NPS regarding the acceptability of the visibility monitoring program and studies.

Enviroplan therefore conducted a limited review of the VMP related materials and correspondence as part of the BART review. Based on this limited review, Enviroplan notes the following:

- The monitoring program would have occurred at a time of greater potential for plant emissions, given the operation of HCCP and no FGD system in place on Unit 1.
- The above notwithstanding, correspondence from ADEC to GVEA on 12/14/99 expressed concern over whether both boilers were operating during the year at typical, full operating rates representative of normal maximum emission rates. It is known that HCCP did not reach full operational status. However, it is unclear whether Unit 1 was at full capacity during the VMP, although Section 1 of GVEA's final report (summarized above) indicates this to be the case.
- It is acknowledged that the NPS did not identify any visibility events during the 2-year monitoring period which would have required further investigation by GVEA. It is also acknowledged that the EPA/NPS/ADEC approved on May 1, 2000 the shutdown of the visibility monitors. However, it is unclear whether lack of correspondence from the NPS during the monitoring program is indicative of agency concurrence with GVEA that no instances of visible plume events occurred that would have required further investigation.
- A very limited review of quarterly video monitoring program results has been conducted by Enviroplan. The quarterly data capture rates are generally high. While relatively few events ("anomalies") are identified in the reports, events are nonetheless identified. For instance, the initial report submitted for the 1st quarter 1998 identifies several events wherein the plant's plume may have entered the Class I area. The same report also indicates the NPS

observers did not report any events. It is unclear whether the lack of reporting by the NPS observer means there was no visible impact at DNPP from Healy during any of these events.

Based on the above, Enviroplan recognizes the general findings of GVEA's VMP and the actual monitored visibility impacts from Healy at the DNPP Class I area. However, Enviroplan has concluded that these results, even if accurately summarized by GVEA in their final report, cannot be considered in terms of the BART control determination for Healy Unit 1 for the following reasons:

- The MOA did not address possible future requirements. A BART Determinations is a case by case evaluation of retrofit technology. Existing emissions reduction technology factors into this evaluation by reducing the number of additional retrofit technologies available and by reducing the cost effectiveness of adding those retrofit technologies. The Department and its contractor included these factors in its evaluation of the available technologies
- In a February 10, 2009 teleconference between the National Park Service (NPS) and the Department, the NPS noted that the VMP conducted by GVEA was a plume blight monitoring study (i.e., monitoring study focusing on the potential impact of a plume of specified emissions for specific transport and dispersion conditions), the results of which cannot be used to satisfy the requirements of the BART program which pertains to visibility impairment due to regional haze.
- There is a lack of formal agency acknowledgement and approval of the results and findings of the VMP.
- It is not clear whether the NPS agreed with the findings in the quarterly monitoring summary reports, and the conclusion by GVEA that no reporting by the NPS equates to no visible impacts by Healy at DNPP during an "anomalous" event.
- The BART rule does not exempt a source from considering impacts associated with visibility modeling if a source has conducted visibility monitoring.
- The BART rule does not indicate that all feasible retrofit technologies can be dismissed if a source has conducted visibility monitoring which suggests no or limited visible impacts at the nearest Class I area.
- The VMP has limited application and is not completely relevant to the BART rule. Specifically, an air dispersion model (CALPUFF in this case) is a tool used to assess potential air quality impacts associated with emissions from a source (or sources). Typically, air modeling is conducted over a large geographic area to ensure air quality compliance. While an ambient monitoring program provides actual measurement and impact information, such data is limited to the specific location or area where the monitoring equipment is sited. As such, while air dispersion models tend to be conservative predictors of air quality versus similarly measured data, the BART rule requires a visibility assessment at the entire Class I area and not simply at select locations at or near the area (i.e., the three VMP locations).

In addition to the above, during a February 27, 2009 teleconference with the Department, GVEA noted that use of a dispersion model, i.e., CALPUFF, is "theoretical" in its application. GVEA requested that greater consideration of real data, e.g., their VMP, be given by the Department when determining BART since no visibility impairment has been monitored at DNPP. In response to this request, Enviroplan has conducted an evaluation of potential impairment at DNPP and its relation to the current Alaska BART/SIP effort for reducing visibility impacts.

This evaluation is based primarily on visibility monitoring data collected at the DNPP IMPROVE monitor site, plus other available information provided by the Department relating to regional haze studies at DNPP. As summary of our review and findings follows below.

The federal Regional Haze Rule requires that states develop plans that include reasonable progress goals for improving visibility in Class I areas to natural conditions by 2064. Natural visibility conditions are intended to represent the long-term visibility in Class I areas without man-made impairment. Specifically, a state is required to set progress goals for Class I areas that: 1) provide for an improvement in visibility for the 20% most impaired (i.e., worst visibility) days and 2) ensure no degradation in visibility for the 20% least impaired (i.e., best visibility) days. Based on the U.S. EPA default approach for estimating natural visibility conditions, the 20% best visibility and 20% worst visibility days at the Denali National Park and Preserve have been estimated to be 2.30 and 7.42 deciviews (dv), respectively (U.S. EPA, "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule," EPA-454/B-03-005, September 2003).

The 2000-2004 average, or baseline, visibility for Denali for the 20% worst days is 9.9 dv, based on data collected at the Denali IMPROVE monitor site. This baseline value, which is higher than the natural visibility deciview value of 7.42, indicates that a rate of progress of 0.04 dv per year is needed for the Class I area to meet natural conditions by 2064. The 2000-2004 baseline, as well as more recent IMPROVE data at Denali, clearly indicate that there is visibility impairment at the Class I area (i.e., the area is not currently at natural conditions).

An inspection of the IMPROVE particulate matter chemical speciation data indicates the year-round presence of sulfates and nitrates, which are primarily derived from combustion sources. The acidic sulfate aerosols that comprise Arctic Haze are known to have a substantial impact on visibility at Denali primarily during November-May and are believed to originate mainly from industrial emissions in northern Europe and Asia. Local (i.e., Alaskan) industrial sources of sulfates and nitrates also exist, which may impact visibility within the Denali Class I area year-round.

Further technical evidence suggests that emissions from the GVEA Healy Power Plant potentially contribute to visibility impairment within the Denali Class I area. An analysis of air trajectories using the National Oceanic and Atmospheric Administration Hybrid Single Particle Lagrangian Integrated Trajectory (HYSPLIT) model indicates that Denali is impacted to some degree by atmospheric transport from the northeast, which suggests that emissions from the GVEA Healy Power Plant potentially contribute to visibility impairment within the Class I area (Hafner, W.D., N.N. Solorzano, and D.A. Jaffe, "Analysis of Rainfall and Fine Aerosol Data Using Clustered trajectory Analysis for National Park Sites in the Western U.S.," *Atmospheric Environment* (2007)). Furthermore, the CALPUFF modeling that was conducted by CH2M Hill in support of the GVEA Healy Power Plant BART Analysis (Final Report submitted January 2, 2009) clearly indicates that emissions from the GVEA plant are expected to impact Denali. The CALPUFF Model simulates the influences of complex terrain on plume transport over local and regional scales. This modeling utilized one full year (2002) of 15-km resolution MM5 data, surface meteorological data from five sites, local terrain and land use data, and emissions and stack parameter data for the 25-MW boiler (Healy Unit #1). CALPUFF modeling results indicated that, under plant baseline (i.e., existing (pre-BART) control) operating conditions, the Denali Class I area was significantly impacted by the boiler emissions 136 days during the year, as defined by a deciview value of 0.5 or greater, and had a maximum delta-deciview value (i.e., above the natural background) of 3.359 dv.

In summary, based on a review of IMPROVE and other relevant data, Enviroplan has determined that DNPP is not without visibility impairment, and it is likely that GVEA is a contributor to this impairment. With respect to GVEA's statement regarding the "theoretical" nature of a dispersion model, it is emphasized that CALPUFF is the regulatory dispersion model recommended by EPA for application in the BART determination process (40 CFR 51, Appendix Y). The CALPUFF model has been utilized by WRAP - RMC in their visibility modeling analysis. The BART rule does not provide an exemption from visibility impact modeling if ambient monitoring data are available. Based on these regulatory provisions, as well as the IMPROVE and other data evaluations discussed above, it is determined that the GVEA visibility monitoring program does not otherwise replace the CALPUFF visibility modeling results considered in this BART determination process for GVEA.

7.4 Visibility Impacts Evaluation Conclusions

A detailed review of the GVEA BART-eligible source visibility modeling analysis has been conducted for the Healy power plant Unit 1 and Auxiliary Boiler #1. A limited review of materials pertaining to the 2-year visibility monitoring program performed by GVEA at the DNPP Class I area also has been conducted. Enviroplan presents the following conclusions pertaining to GVEA's visibility impacts determination:

- The CALPUFF visibility modeling analyses are in conformance with the protocol used by WRAP – RMC ("Draft Final Modeling Protocol CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States", August 15, 2006), and WRAP's, "Summary of WRAP RMC BART Modeling for Alaska" (Draft#7, April 6, 2007).
- The CALPUFF visibility modeling analyses are generally in conformance with the Federal and State BART guidelines. While GVEA did consider two modeling scenarios for the current configuration, their use of peak 24-hour emission rates to reflect a "baseline" plant configuration is consistent with the BART rule. No consideration is given to their modeled "null" scenario.
- Maximum predicted visibility impacts for Auxiliary Boiler #1 (0.067 dV) are well below the 0.5 deciview significant visibility impairment metric. Consistent with the individual source attribution approach in Appendix Y, no additional controls are required for this unit.
- Each NO_x emissions control option considered for Unit 1 results in a greater than significant visibility improvement (i.e., greater than 0.5 dV) when compared against the maximum predicted daily visibility impact "baseline" scenario, with the low NO_x burner/OFA plus SCR system showing the greatest visibility improvement (3.359 ΔdV versus 2.573 ΔdV, or a 0.786 dV reduction).
- For the SO_2 emissions control options considered for Unit 1, the retrofit scenario of increased sorbent feed rate to the existing FGD results in only a 0.25 dV improvement versus the impacts associated with the baseline scenario (i.e., ½ of the significance level), and the visibility impacts associated with a lime spray dryer FGD system and wet limestone FGD system are worse than the current baseline configuration due to reduced plume height from a relatively

colder, wetter plume. Coincidentally, the number of days exceeding the significance level (0.5 dV) increases for each of these control options versus the current baseline configuration.

- On February 12, 2009 and during the proposed BART comment period, the NPS commented on the predicted worsening of modeled visibility impacts attributable to the lime spray dryer FGD system and wet limestone FGD system. The NPS questioned the use of CALPUFF and GVEA's receptor grid. The bases for these comments are unclear. The Department, EPA and the federal land managers (which included the NPS) discussed the basic modeling approach several years ago so that these types of issues could be resolved *before* WRAP and industry conducted their assessments. GVEA followed the 2006 WRAP modeling protocol, which the Department discussed with the NPS during the protocol development phase. The Department also had subsequent modeling conversations with the NPS (and industry) regarding source-specific assessments, without the NPS ever challenging the modeling platform (other than which version of CALPUFF should be used and which of the numerous "switches" in CALPUFF should be selected). The NPS likewise did not challenge the use of CALPUFF when the Department adopted the WRAP protocol by reference in its BART regulations. Therefore, the Department deems this comment as extremely delinquent, especially considering that a model change at this point of the process would mean further substantive delays to the development of the state's visibility SIP. In regards to the receptor grid comment, WRAP and GVEA used an NPS-generated receptor grid which they obtained through an NPS their web-site. The Department sees no merit in changing modeling approaches, as it is too late in the SIP development process to make such a substantive change. Visibility-related cost effectiveness information is provided for each NO_x emissions control scenario in terms of both deciviews and days above 0.5 dV reduced. This information is summarized below:

Table 7-1: Visibility Improvement and Annual Costs for NO_x Control Options*

BART Controls	Highest dV Reduction (ΔdV)	Reduction in Avg. No. of Days Above 0.5 dV (Days)	Annualized Cost ($/Year)	Cost per dV Reduction ($/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV ($/Day Reduced)
Optimizing Existing LNB w/ OFA	0.560	43	$3,480	$6,214	$81
Replace OFA w/ ROFA®	0.671	56	$934,426	$1,392,587	$16,686
Replace OFA w/ ROFA® and Rotamix®	0.736	67	$1,490,066	$2,024,546	$22,240
LNB/OFA/SNCR	0.620	51	$563,985	$909,653	$11,059
LNB/OFA/SCR	0.786	71	$4,929,185	$6,271,228	$69,425

*Reflects 8-year capital cost amortization period.

Aside from the current baseline configuration, the most cost effective additional control is optimization of the existing configuration (low NO_x burners/OFA). The most costly control expressed in dV and days above 0.5 dV is the addition of an SCR system. Similar cost effectiveness information is presented for the SO_2 control scenarios; however, costing information for the lime spray dryer FGD system and wet limestone FGD systems expressed in terms of visibility metrics are not meaningful since the visibility impacts worsen under these control scenarios.

Table 7-2: Visibility Improvement and Annual Costs for SOx Control Options[1]

BART Controls	Highest dV Reduction (ΔdV)	Reduction in Avg. No. of Days Above 0.5 dV (Days)	Annualized Cost ($/Year)	Cost per dV Reduction ($/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV ($/Day Reduced)
Increase Dry Sodium Bicarbonate FGD System (increase feed rate)	0.250	39	$753,802	$3,015,208	$19,328
Install Lime Spray Dryer FGD System	-0.870	20	$2,085,738	-$2,397,400[2]	$104,287
Install Wet FGD System	-1.160	18	$3,519,262	-$3,033,847[2]	$195,515

(1) Reflects 8-year capital cost amortization period.
(2) Reflects an increase in visibility impact versus existing baseline impacts.

Overall, the results of the modeling demonstrate that no controls are required for Auxiliary Boiler #1. Also, the lime spray dryer FGD system and wet limestone FGD system SO_2 retrofit options for Unit 1 show a worsening of visible impacts as predicted at DNPP, and Enviroplan agrees with GVEA that these options are not considered viable as SO_2 BART for Unit 1. Enviroplan also finds that the high cost effectiveness associated with an insignificant prediction of visibility improvement from increased sorbent injection at the existing FGD system, when combined with the findings associated with other steps in the BART analysis process, i.e., increased potential for visible impacts (brown plume), results in the sorbent injection increase option not being viable as SO_2 BART for Unit 1.

8. PROPOSED BART FOR HEALY 1

The proposed BART for Healy 1 presented in the April 27, 2009 BART Findings Report included installation of a SCR control system for additional NO_x control; the existing dry FGD sodium carbonate injection system for continued SO_2 control; and the existing fabric filter (baghouse) for filterable particulate (and SO_2) control. Comments pertaining to proposed BART were received during the related 35-day notice period (May 12, 2009 - June 15, 2009); and, as indicated in this document, all comments have been addressed in the RTC document. As discussed in this report, several of the comments have resulted in changes to the Healy 1 NO_x and SO_2 retrofit option cost analyses and emission rates.

In addition to the above, comments were received from GVEA and the NPS pertaining to the relevance of other BART determinations and their costs, which should be considered when determining BART for Healy 1. The RTC document provides a detailed response to these comments, including tabular summaries of other BART determinations for similar EGUs to Healy 1. The tabular summaries were derived from August 2009 NPS survey data[8] for western U.S. primarily coal-fired EGUs. The Department has considered the NPS survey data in deciding a final BART determination for Healy 1. Appendix A to this Findings Report includes the NO_x and SO_2 statistical data summaries derived from the NPS survey data. This information is reflected in the decisions discussed below.

The following sections discuss the BART control recommended for Healy 1.

8.1 NO_x Control at Healy Unit 1

Table 8-1 presents a comparison matrix of the GVEA-evaluated NO_x control options as they relate to the BART 5-step control review process. The cost effectiveness information is based on an 8-year remaining useful lifetime of Healy 1 as referenced from the projected SIP required retrofit control implementation date of calendar year 2016 (i.e., end date of calendar year 2024). As discussed in Section 6 of this document, the BART rule does support the use of the 8-year lifetime period for the amortization of capital control costs.

[8] NPS BART Evaluation, http://www.wrapair.org/forums/ssjf/bart.html .

Table 8-1: Comparison Matrix of the GVEA-Evaluated NO_x Control Options as they Relate to the BART 5-Step Evaluation Process

Control Option	BART Analysis Steps				
	Identify All Control Options (Step 1)	**Eliminate Technically Infeasible Options (Step 2)**	**Evaluation of Control Effectiveness[(2)] (Step 3)**	**Cost-Effectiveness and Impacts Analysis[(3)] (Step 4)**	**Visibility Impact Evaluation[(4)] (Step 5)**
Existing LNB w/OFA[(1)]	Option Identified	Option Accepted	0% (0.28 lb/MMBtu)	N/A	N/A
Optimize Existing LNB w/OFA	Option Identified	Option Accepted	18% (0.23 lb/MMBtu; 74 add'l tons NO_x removed)	\$47/ton NO_x (annual) \$47/ton NO_x (incremental) \$6,214/deciview	0.560 deciview improvement; 43 day improvement
LNB w/OFA, plus new SNCR system	Option Identified	Option Accepted	32% (0.19 lb/MMBtu; 134 add'l tons NO_x removed)	\$4,208/ton NO_x (annual) \$9,409/ton NO_x (incremental) \$909,653/deciview	0.620 deciview improvement; 51 day improvement
Replace OFA w/ROFA®	Option Identified	Option Accepted	46% (0.15 lb/MMBtu; 194 add'l tons NO_x removed)	\$4,827/ton NO_x (annual) \$6,219/ton NO_x (incremental) \$1,392,587/deciview	0.671 deciview improvement; 56 day improvement
Replace OFA w/ROFA® & Rotamix®	Option Identified	Option Accepted	61% (0.11 lb/MMBtu; 253 add'l tons NO_x removed)	\$5,886/ton NO_x (annual) \$9,328/ton NO_x (incremental) \$2,024,546/deciview	0.736 deciview improvement; 67 day improvement
LNB w/OFA, plus new SCR system	Option Identified	Option Accepted	75% (0.07 lb/MMBtu; 313 add'l tons NO_x x removed)	\$15,762/ton NO_x (annual) \$57,734/ton NO_x (incremental) \$6,271,228/deciview	0.786 deciview improvement; 71 day improvement

Notes:

(1) The existing controlled NO_x baseline emission rate is 0.28 lb/MMBtu (30-day average). No effectiveness, capital or operating costs, or visibility improvements are applicable to this existing control scenario.

(2) Percent control (%) is relative to the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system. The NO_x emission limit corresponding to the option; and the additional amount of NO_x removed (tons/year) for this control scenario versus existing baseline is also shown.

(3) Cost-effectiveness estimates based on 8-year Healy 1 remaining useful lifetime.

(4) Visibility impacts for each option are relative to existing baseline conditions.

GVEA has proposed the existing low NO_x burner and over fire air NO_x emissions control system as BART for Healy 1. In our April 27, 2009 proposed BART Findings Report, Enviroplan recommended the addition of SCR to the existing LNB/OFA system; however, the site-specific cost evaluation and revised cost analysis discussed herein have resulted in the installation of SCR being deemed cost prohibitive.

The above notwithstanding, Enviroplan recommends the final BART determination for Healy Unit 1 to be a NO_x emission limit consistent with a new SNCR system. It is emphasized that the recommendation is not the installation of SNCR; rather, it is the NO_x emission limit that would be achieved should GVEA opt to install an SNCR system on Healy 1 to comply with this limit.

This final BART determination is proposed by Enviroplan for the Unit 1 BART-eligible source pursuant to 18 AAC 50.260(l).

As indicated in 40 CFR 51, Appendix Y, the underlying goal of the BART rule, and the regional haze program, relates to the Clean Air Act's national goal of eliminating man-made visibility impairment from all Class I areas. Based on these regulatory programs; 18 ACC 50.260; and all of the information presented herein in response to these programs, Enviroplan believes the NO_x emission limit equivalent to the SNCR control retrofit option for Healy 1 represents the best combination of factors (steps evaluated) under the BART rule and regional haze program for the purpose of improving visibility impairment at DNPP Class I area. The basis for this determination is as follows:

1. Healy 1 Power Plant is located in very close proximity (about 8 km) to the DNPP Class I area, with the potential for substantive visible impacts at the Class I area (as predicted with CALPUFF).
2. The Healy 1 unit already utilizes the best system of particulate pollutant control (high efficiency baghouse), and the existing configuration for SO_2 control (FGD system) is considered as BART (see below). However, various alternative retrofit NO_x controls are potentially applicable to Healy 1 for substantive additional reduction in unit NO_x emissions.
3. When compared to the existing baseline configuration for Healy 1, visibility modeling of each retrofit option, including optimizing the existing LNB/OFA system, shows predicted significant visibility improvement (greater than 0.5 deciviews) at DNPP; with a coincident predicted reduction of about 1.5 months (or more) in total days exceeding 0.5 deciviews.
4. When compared to the full range of EGUs, as well as the subset of EGUs whose capacities are relatively comparably with Healy 1 (25 MW), the cost effectiveness of each retrofit system except the optimization option is greater than the NPS survey's maximum dollars per ton of pollutant removed metric (i.e., about $3800/ton as shown in Appendix A). The SNCR option is about 11 percent above this cost, while the most expensive option, SCR, is approximately 15 times this cost.
5. Except for the SCR option, when expressed in dollars per deciview improved ($/dv) each retrofit option is cost effective in comparison to the NPS survey's mean and median cost values (Appendix A) for other EGUs, including those EGUs relatively comparable in capacity (<110 MW) to Healy 1.
6. Comparison of each option's cost metrics suggests optimization of the existing LNB/OFA system to be the most cost effective retrofit option; however, GVEA has expressed doubt about the ability of this option to achieve the NOx reduction and emission limit expressed in Table 8-1.
7. The SNCR (and Rotamix®) option can employ a urea-based reagent to minimize deleterious environmental impacts associated with ammonia-based reagent handling/storage systems.
8. GVEA has indicated in their January 2009 report that the ROFA® (and optimization) option <u>may</u> result in increased carbon monoxide (CO) and level of ignition (unburnt carbon) emissions.
9. The visibility impact modeling done for Healy 1 indicates that the existing LNB/OFA system results in 136 days per year when the visibility impacts attributable to Healy 1 exceed 0.5 deciviews at DNPP. The NO_x emission limit equivalent to the SNCR control option reduces

the number of days with modeled impacts over 0.5 deciviews to 85. The NO_x emission limit for this option significantly reduces the predicted number of days with modeled impacts over 0.5 deciviews by an additional 51 days per year.

10. The NO_x emission limit equivalent to the SNCR control option will reduce the highest delta deciview impacts from 3.359 ΔdV to 2.739 ΔdV, which is a reduction in visible impacts in excess of the significance metric, 0.5 dV.
11. The NO_x emission limit equivalent to the SNCR option is expected to reduce NO_x emissions by 32% from existing baseline emissions, which equates to 134 tons of additional NO_x emissions removed from the Healy 1 exhaust gas stream.
12. Although the cost effectiveness for the SNCR option is greater than the presumptive $1500/ton cost effectiveness value cited in the preamble to the EPA's BART Guideline (70 FR 39135), the $1500 effectiveness value is not a ceiling value, and it must be considered with all other BART review aspects and control cost effectiveness metrics as presented herein.
13. The incremental ratepayer increase for the addition of the SNCR option is $0.00041/kWh, an average increase of about 0.23 percent. For a family that uses 500 kWh/month, the addition of SNCR would cost $0.21/month and $2.46/year.

Based on the multiple reasons indicated above, the Department has determined the NO_x BART emission limit for Healy 1 to be the equivalent of the existing LNB/OFA system with a new SNCR system; however, the Department has set the NOx emission limit at 0.20 lb/MMBtu rather than 0.19 lb/MMBtu. This determination is based on consideration of all elements of the BART 5-step evaluation process, including the general cost acceptability ($/ton and $/dV); the proximity of Healy 1 to DNPP; the additional reduction in NO_x emissions; and related predicted visibility improvement at DNPP necessary for the Department to meet the reasonable progress compliance goals by 2064.

8.2 SO_2 Control at Healy Unit 1

Table 8-2 presents a comparison matrix of the GVEA-evaluated SO_2 control options as they relate to the BART 5-step control review process. The cost effectiveness information is based on an 8-year remaining useful lifetime of Healy 1 as referenced from the projected SIP required retrofit control implementation date of calendar year 2016 (i.e., end date of calendar year 2024). As discussed in Section 6 of this document, the BART rule does support the use of the 8-year lifetime period for the amortization of capital control costs.

Table 8-2: Comparison Matrix of the GVEA-Evaluated SO_2 Control Options as they Relate to the BART 5-Step Evaluation Process

Control Option	BART Analysis Steps				
	Identify All Control Options (Step 1)	**Eliminate Technically Infeasible Options (Step 2)**	**Evaluation of Control Effectiveness[2] (Step 3)**	**Cost-Effectiveness and Impacts Analysis[3] (Step 4)**	**Visibility Impact Evaluation[4] (Step 5)**
Existing Dry[1] FGD System (Sodium Bicarbonate Sorbent)	Option Identified	Option Accepted	0% (0.30 lb/MMBtu)	N/A	N/A
Optimize Existing FGD System by Increasing Sorbent Injection	Option Identified	Option Accepted	40% (0.18 lb/MMBtu; 179 add'l tons SO_2 removed)	\$4,218/ton SO_2 (annual) \$4,218/ton SO_2 (incremental) \$3,015,208/deciview	0.250 deciview improvement; 39 day improvement
Install Lime Spray Dryer Semi-Dry FGD System	Option Identified	Option Accepted	50% (0.15 lb/MMBtu; 223 add'l tons SO_2 removed)	\$9,337/ton SO_2 (annual) \$29,813/ton SO_2 (incremental) -\$2,397,400/deciview	-0.870 deciview improvement; 20 day improvement
Install Wet Limestone FGD System	Option Identified	Option Accepted	77% (0.07 lb/MMBtu; 343 add'l tons SO_2 removed)	\$10,275/ton SO_2 (annual) \$12,033/ton SO_2 (incremental) -\$3,033,847/deciview	-1.160 deciview improvement; 18 day improvement

Notes:
(1) The existing controlled SO_2 baseline emission rate is 0.30 lb/MMBtu (30-day average). No effectiveness, capital or operating costs, or visibility improvements are applicable to this existing control scenario.
(2) Percent control (%) is relative to the existing controlled baseline configuration for Healy 1, defined as LNB+OFA NO_x control system; sodium bicarbonate sorbent dry FGD SO_2 control system; and 12 compartment reverse-gas fabric filter particulate (with coincident SO_2) control system. The SO_2 emission limit corresponding to the option; and the additional amount of SO_2 removed (tons/year) for this control scenario versus existing baseline is also shown.
(3) Cost-effectiveness estimates based on 8-year Healy 1 remaining useful lifetime. Negative values (\$/dV) for lime spray dryer and wet FGD reflects a worsening (i.e., increase) in maximum predicted visibility impacts compared to baseline.
(4) Visibility impacts for each option are relative to existing baseline conditions.

Review of NPS survey data (i.e., Appendix A) for all EGUs indicates respective median and mean SO_2 cost effectiveness values of \$1379/ton and \$1721/ton; and about \$14.5 million/dv and \$10.5 million/dv. While the Department has considered similar data for relatively comparable small EGUs (<100 MW), the general paucity of small affected units does not make such information meaningful for comparison Healy 1 (i.e., there are only four EGUs in the NPS survey data with capacities less than 100 MW, with median and mean cost effectiveness values of about \$5000/ton).

The Department has determined the following with respect to final SO_2 BART for Healy 1.

1. Due to the high cost effectiveness values (\$/ton) presented in Table 8-2, the installation of a wet limestone FGD on Healy 1 is not considered economically feasible. In addition, a new lime spray dryer FGD system also presents excessively high cost per ton values, including the incremental cost.

2. In addition to the relatively high costs associated with the wet FGD and lime spray dryer FGD options, both the wet and dry retrofits are predicted to increase visibility impairment at DNPP due to a cooler, reduced plume.
3. The increased sorbent injection option shows an insignificant predicted improvement in visibility at DNPP. The cost for this option is within the dollar per deciview ($/dv) metric for all EGUs as cited above; but it is about 2.5 to 3 times greater than the median and mean values ($/ton) indicated above. Further, a disparity exists when comparing the almost same NO_x and SO_2 cost effectiveness values. The final recommended NO_x BART option (emission limit equivalent to SNCR) has a cost effectiveness of $4,208/ton, with a coincident significant predicted visibility improvement of 0.620 dv; however, a similar SO_2 cost effectiveness for the optimized FGD option ($4,218/ton) results in only a 0.25 dv predicted improvement in visibility. The Department believes this cost disparity supports the NO_x control; but does not support the optimization SO_2 control option.
4. The increased sorbent injection option will result in the increased potential for visibility impairing brown plume.

Based on the multiple reasons indicated above, the Department has determined that final SO_2 BART for Healy 1 is the current FGD configuration and no additional controls are recommended for the Healy 1 boiler to reduce SO_2 emissions. The emission limit equivalent to the existing FGD system will be set by the Department as the BART emission limit for SO_2.

8.3 Particulate Control at Healy Unit 1

A baghouse is considered the state-of-the-art filterable particulate emissions control technology for utility boiler applications. Therefore, the existing high-efficiency reverse gas baghouse installed on Healy Unit 1 is considered BART. The particulate emission limit for Healy 1 (see Section 9) is reflective of filterable particulate matter (see related discussion, Section 3.3).

9. GVEA BART CONTROL ANALYSIS REPORT FINDINGS AND CONCLUSIONS

The objective of this review has been to document Enviroplan's findings regarding GVEA's BART control analysis. Enviroplan initially conducted a review of the July 2008 BART control analysis to determine compliance with 18 AAC 50.260(e) through (h). The July 2008 report was revised and resubmitted by GVEA in January 2009; GVEA provided additional relevant supplemental information on March 18, 24 and 30, 2009; and Enviroplan prepared a findings report containing a proposed preliminary BART determination for each BART-eligible source at this facility, consistent with 18 AAC 50.260(j). The April 27, 2009 findings report concluded that the GVEA BART control analysis complied with 18 AAC 50.260(e) through (h); and it proposed BART for Healy 1 as the existing dry sorbent injection system (SO_2); the addition of a SCR system (NO_x); and the existing reverse gas baghouse system (PM_{10}). For Auxiliary Boiler #1, the existing configuration (i.e., no air pollution control systems) was determined as BART.

The Department noticed the April 27, 2009 Findings Report and proposed BART determination for the Healy plant. The notice period occurred from May 12, 2009 through June 15, 2009. Comments received were addressed in a RTC document. This report provides the recommended final BART determination for the Healy plant pursuant to 18 AAC 50.260(l), taking into account as necessary the comments and additional information received during the comment period. There is no change in the final BART determination for Auxiliary Boiler #1 (i.e., no controls; current TV permit emission limitations including equivalent limitations in units of lb/MMBtu), and the final BART determination for Healy 1 was presented in Section 8.

9.1 BART Emission Limits

The final BART emission limits recommended for Healy Unit 1 in accordance with 18 AAC 50.260(l) are summarized in Table 9-1 below. As discussed herein, the BART emission limits are based on an 8-year remaining useful life for Healy 1 (from calendar year 2016) which is provided for at Section IV.D.4.K of 40 CFR 51, Appendix Y. The BART emission limits are compared to current permitted pollutant emission limits which remain in effect.

Table 9-1: Final BART Emission Limits Recommended for the GVEA Healy Power Plant

	Particulate		SO_2		NOx	
	Current [1]	BART [2]	Current [1]	BART [2]	Current [1]	BART [2]
Healy Unit 1	0.05 gr/dscf 36.7 lb/hr (hourly average at full load) 161 ton/yr	0.015 lb/MMBtu (based on compliance source testing)	258 lb/hr (24-hour average, calendar day) 367 lb/hr (3-hour average) 472 ton/yr	0.30 lb/MMBtu (30-day rolling average) [3]	429 ton/yr	0.20 lb/MMBtu (30-day rolling average)
Auxiliary Boiler #1	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average 1 ton per calendar year	0.05 gr/dscf, hourly average (0.8 lb/hr at full load) 20% load factor, annual average	0.3% S in oil, annual average 0.5% S in oil, 3-hour average	0.53 lb/MMBtu (30-day rolling average)	20 lb NOx/1000 gal distillate fuel, annual average 20% load factor, annual average	0.15 lb/MMBtu (30-day rolling average).

1. Taken from Permit No. 173TVP01, Table 2.
2. BART emission limits for Unit 1 are in addition to the current (existing) emission limits. The BART emission limit for particulate reflects filterable PM_{10}.

The recommended BART emission limits of Table 9-1 are reflective of the vendor/test-based limits provided by GVEA. This notwithstanding, as indicated in the April 27, 2009 findings report, GVEA requested on March 18, 2009 that their BART emission limits be revised to account for potential operating variability. GVEA conducted an analysis of 2003-2008 (5 years) 30-day rolling NO_x and SO_2 emissions from Healy Unit 1. GVEA applied three standard deviations to the mean, and requested that their BART emission limits reflect the resultant rates at three standard deviations. Given the long-term nature of the NO_x and SO_2 emissions averaging period (30-days); and the fact that the emission limits provided by GVEA are mean values which inherently account for variability, Enviroplan believes that the Table 9-1 BART emission limits will adequately account for any short-term upset or malfunction conditions. Therefore, no change has been made to the GVEA emission limits.

The existing (current) emission limits shown in Table 9-1 were established pursuant to regulatory requirements other than the BART rule. For example, the SO_2 limits of 258 lb/hr (24-hour average) and 367 lb/hr (3-hour average) were established to protect the short-term SO_2 air quality standards. Part 71 Permit AQ0173TVP01 provides the basis for each of the existing emission limits. While the existing short-term emission limits for PM_{10} and SO_2 are larger than the 24-hour average emission rates used by GVEA in the visibility impact modeling (i.e., 6.29 and 182.2 lb/hr, respectively), BART emission limits are prescribed on a mass per heat input basis and a 30-day rolling basis for SO_2 and NOx per 40 CFR 51, Appendix Y, Section V. Therefore, the proposed preliminary BART emission limits presented in Table 9-1 are not intended to replace the existing pollutant emission limits.

9.2 Compliance Demonstration

Consistent with 18 AAC 50.260(l) and 40 CFR 71.6(a)(3), monitoring, record-keeping, and reporting (MR&R) conditions needed to demonstrate compliance with the BART emission limits must be established. The following summarizes the recommended MR&R requirements relating to the BART emission limits of Table 9-1. As appropriate, these conditions are consistent with requirements already contained in the Part 71 operating permit for the Healy Power Plant.

Healy Unit 1:

1. The Permittee shall limit NOx, SO_2 and PM_{10} emissions from EU ID 1 in accordance with the BART limits indicated in Table 9-1.

    1.1 The Permittee shall demonstrate compliance with the NO_X, SO_2 and PM_{10} emission limits for EU ID 1 as follows:

    a. Use continuous emission monitors to determine emissions of NO_X and SO_2 from EU ID 1.

    i. Monitor, record and report in accordance with Conditions 1.2 and 1.3.

    b. Use source test results to determine emissions of PM_{10} from EU ID 1.

    i. Monitor, record and report in accordance with Condition 1.4.

    1.2 In accordance with Condition 1.1a and the Part 71 operating permit for this stationary source, the Permittee shall install and operate a continuous emission monitoring system on the EU ID 1 boiler exhaust duct to measure and record the sulfur dioxide and oxides of nitrogen emissions discharged to the atmosphere.

    a. Monitor, record , and report in accordance with Condition 1.3.

    b. Submit a Quality Assurance Plan to the Department for the continuous emission monitoring system in accordance with the Part 71 operating permit for this stationary source.

    c. Comply with the applicable Performance Specification set out in Title 40 Code of Federal Regulations Part 60, Appendix B, in accordance with the Part 71 operating permit for this stationary source.

    1.3 In accordance with Condition 1.2a and the Part 71 operating permit for this stationary source, the Permittee shall monitor, record and report the following information:

    a. Measure and record the 60-minute average emission rate of NO_x. Record for each operating date the average daily NO_x emission rate (in lb/MMBtu). Determine compliance with the NOx emission limit of Table 9-1 by calculating the arithmetic average of all hourly emission rates from EU ID 1 for NOx for the 30 successive boiler operating days, except for data obtained during startup, shutdown and malfunction or emergency conditions. Record all instances of startup, shutdown and malfunction or emergency conditions occurring during each 30-day rolling averaging period.

b. Measure and record the 60-minute average emission rate of SO_2. Record for each operating date the average daily SO_2 emission rate (in lb/MMBtu). Determine compliance with the SO_2 emission limit of Table 9-1 by calculating the arithmetic average of all hourly emission rates from EU ID 1 for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown and malfunction or emergency conditions. Record all instances of startup, shutdown and malfunction or emergency conditions occurring during each 30-day rolling averaging period.

c. Measure and record the 60-minute average stack gas concentration of oxygen or carbon dioxide.

d. Measure and record the 60-minute average coal feed rate to EU ID 1.

e. Report for each operating day, the average daily NOx and SO2 emission rates (lb/MMBtu); the 30-day rolling average NOx and SO2 emission rates (lb/MMBtu); and the amount of coal combusted (tons).

f. Submit an initial compliance status report within six months of the final BART emission limit compliance date established by the Department.

g. Submit a report in accordance with the *Excess Emissions and Permit Deviations* condition of the Part 71 operating permit whenever the 30-day rolling average NOx or SO_2 emission rate (lb/MMBtu) exceeds the respective allowable rate in Table 9-1.

1.4 In accordance with Condition 1.1b and the Part 71 operating permit for this stationary source, the Permittee shall demonstrate compliance with the PM_{10} emission limit in Table 9-1 as follows:

a. Conduct source tests for particulate matter (PM_{10}) as follows:

i. Conduct the tests and report the results in accordance with the *General Source Testing and Monitoring Requirements* section of the Part 71 operating permit for source emissions testing of $PM_{10.}$ For tests required under Condition 1.4a.ii, submit a test plan at least 60 days before the deadline for the next test under Condition 1.4a.ii;

ii. Conduct an initial test on EU ID 1 within six months of the final BART emission limit compliance date established by the Department;

iii. Conduct additional tests on EU ID 1 within 8760 operating hours of the previous test;

iv. During each test, measure and record baghouse minimum and maximum one-minute pressure drops. Submit the records with the source test report.

b. Comply with the monitoring, recordkeeping and reporting requirements of the Permittee's Compliance Assurance Monitoring (CAM) Plan for particulate emissions from EU ID1 for the monitoring of baghouse pressure differential.

Auxiliary Boiler #1:

2. The Permittee shall limit NOx, SO_2 and PM_{10} emissions for Auxiliary Boiler #1 in accordance with the BART limits indicated in Table 9-1.

2.1 The Permittee shall demonstrate compliance with the NO_X, SO_2 and PM_{10} emission limits for Auxiliary Boiler #1 as follows:

a. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the **Visible Emissions Monitoring, Recordkeeping and Reporting** requirements.

b. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the **PM Monitoring, Recordkeeping and Reporting** requirements.

c. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the **Sulfur Compound Emissions Standards Requirements.**

d. In accordance with ***Section 3*** of the Part 71 operating permit for this stationary source, the Permittee shall continue to comply with the requirements for **BACT, Owner Requested Limits, and Other Title I Permit Requirements**, as applicable to EU ID 3.

Appendix A: NOx and SO2 Statistical Data Summaries of Western U.S. EGU BART Determinations As Derived from the NPS August 2009 Survey Data

Table A1: All EGUs Summarized by the NPS Regardless of Unit Capacity or Type					
NOx Summary Statistics for	**BART at**	**46**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	330	367	790	25	16,875
Presumptive BART limit (lb/mmBtu)	0.23	0.25	0.45	0.10	
Reductions (tpy)	1,607	2,794	12,297	0	125,711
Capital Cost	$9,350,000	$13,776,426	$136,800,000	$0	$606,162,750
Capital Cost ($/kW)	$25	$48	$415	$0	
Total Annual Cost	$1,144,944	$2,423,510	$15,682,702	$0	$106,634,441
Cost-Effectiveness ($/ton)	$785	$1,215	$3,778	$0	
Proposed BART Limit	0.24	0.24	0.43	0.07	
Units	lb/mmBtu	Lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.322	0.413	2.668	0.007	
Cost-Effectiveness ($/98th % dv at Max Class I)	$6,211,484	**$8,964,942**	$34,726,950	$1,141,933	
Visibility Improvement (dv at Summed Class I)	0.627	1.021	5.300	0.015	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$2,515,268	$4,845,809	$15,329,818	$600,126	

Table A2: All EGUs Between 0 – 110 MW Capacity					
NOx Summary Statistics for	**BART at**	**10**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	98	92	113	55	917
Presumptive BART limit (lb/mmBtu)	0.39	0.39	0.39	0.39	
Reductions (tpy)	357	565	1,443	91	5,653
Capital Cost	$1,946,000	$3,481,270	$7,884,900	$790,000	$34,812,700
Capital Cost ($/kW)	$25	$35	$72	$13	
Total Annual Cost	$490,969	$673,959	$1,498,001	$75,000	$6,739,590
Cost-Effectiveness ($/ton)	$1,089	$1,440	$3,040	$413	
Proposed BART Limit	0.20	0.23	0.39	0.12	
Units	Lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.104	0.229	0.630	0.007	
Cost-Effectiveness ($/98th % dv at Max Class I)	$4,829,753	**$6,229,417**	$15,000,000	$2,012,168	
Visibility Improvement (dv at Summed Class I)	0.019	0.019	0.023	0.015	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$5,233,957	$5,233,957	$7,159,091	$3,308,824	

Table A3: All EGUs Up to 100 MW Capacity					
NOx Summary Statistics for	**BART at**	**5**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	83	72	85	55	361
Presumptive BART limit (lb/mmBtu)	0.39	0.39	0.39	0.39	
Reductions (tpy)	165	178	254	91	889
Capital Cost	$1,820,000	$1,587,600	$2,156,000	$790,000	$7,938,000
Capital Cost ($/kW)	$25	$22	$33	$13	
Total Annual Cost	$276,611	$285,930	$574,613	$75,000	$1,429,649
Cost-Effectiveness ($/ton)	$2,415	$1,776	$3,040	$413	
Proposed BART Limit	0.19	0.25	0.39	0.12	
Units	Lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.024	0.032	0.063	0.007	
Cost-Effectiveness ($/98th % dv at Max Class I)	$10,260,946	**$9,872,122**	$15,000,000	$6,250,000	
Visibility Improvement (dv at Summed Class I)	0.019	0.019	0.023	0.015	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$5,233,957	$5,233,957	$7,159,091	$3,308,824	

Table A4: All EGUs Summarized by the NPS Regardless of Unit Capacity or Type					
SO2 Summary Statistics	**BART at**	**32**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	408	377	690	60	12,063
Presumptive BART limit (lb/mmBtu)	0.15	0.15	0.15	0.15	
Reductions (tpy)	5,657	11,668	64,465	233	361,703
Capital Cost	$41,083,000	$64,838,994	$247,300,000	$1,600,000	$1,815,491,833
Capital Cost ($/kW)	$173	$249	$737	$3	
Total Annual Cost	$8,315,432	$10,459,005	$36,600,000	$366,000	$313,770,152
Cost-Effectiveness ($/ton)	$1,379	$1,721	$7,309	$49	
Proposed BART Limit	0.15	0.19	0.60	0.09	
Units	lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.772	0.751	1.745	0.124	
Cost-Effectiveness ($/98th % dv at Max Class I)	$14,533,679	**$19,264,719**	$49,919,355	$3,600,000	
Visibility Improvement (dv at Summed Class I)	1.954	2.949	10.590	0.000	
Cost-Effectiveness ($/98th % dv at Summed Class I)	$5,944,587	$5,768,730	$8,008,511	$3,456,091	

Table A5: All EGUs Up to 100 MW Capacity					
SO2 Summary Statistics	**BART at**	**4**	**EGUs**		
	Median	**Mean**	**Max**	**Min**	**Totals**
Rating (MW Gross)	75	74	85	60	295
Presumptive BART limit (lb/mmBtu)	0.15	0.15	0.15	0.15	
Reductions (tpy)	1,201	1,380	2,238	880	5,519
Capital Cost	$38,000,000	$33,289,333	$46,360,000	$15,508,000	$99,868,000
Capital Cost ($/kW)	$447	$424	$618	$207	
Total Annual Cost	$6,190,000	$4,871,333	$6,556,000	$1,868,000	$14,614,000
Cost-Effectiveness ($/ton)	$5,300	$5,125	$7,309	$2,765	
Proposed BART Limit	0.35	0.36	0.60	0.15	
Units	lb/mmBtu	lb/mmBtu	lb/mmBtu	lb/mmBtu	
Visibility analyses					
Visibility Improvement (dv at Max Class I)	0.187	0.187	0.250	0.124	
Cost-Effectiveness ($/98th % dv at Max Class I)	$38,071,677	**$38,071,677**	$49,919,355	$26,224,000	
Visibility Improvement (dv at Summed Class I)	0.000	0.000	0.000	0.000	
Cost-Effectiveness ($/98th % dv at Summed Class I)	#NUM!	#DIV/0!	$0	$0	

Appendix B: Calpuff Visibility Modeling of GVEA Auxiliary Boiler #1 Using Corrected NOx and SO2 Emissions Data

March 26, 2010
Project No. 209928.01

To: Tom Turner, ADEC, DAQ
Alan Schuler, P.E., ADEC, DAQ

From: Michael Hirtler, Enviroplan Consulting
Ganesh Srinivasan, Enviroplan Consulting

Re: NTP: 18-3001-17-8F
Calpuff Visibility Modeling of GVEA Auxiliary Boiler #1

In accordance with the Department's March 17, 2010 email request on the above referenced project, Enviroplan Consulting conducted a visibility impact modeling assessment of the GVEA Healy Power Plant Auxiliary #1 Boiler. The purpose of this analysis is to determine whether the existing Auxiliary Boiler #1, as a BART eligible unit, exceeds the 0.5 deciview visibility significance metric when the unit is modeled with correct NO_x/SO_2 emission rates.

GVEA submitted an Informal Review Request to the Department on February 24, 2010. Among other issues raised in the Request, GVEA disclosed that Auxiliary #1 Boiler NO_x and SO_2 emission rates, as indicated in the GVEA BART Final Determination Report (February 5, 2010), were each understated by a factor of 1000. These emission rates are consistent with those used by WRAP-RMC in their BART visibility modeling screening analysis; and GVEA used these understated emissions in their BART visibility impact analysis for this boiler. As such, the Department requested Enviroplan to re-model Auxiliary #1 Boiler with the corrected boiler NO_x and SO_2 emission rates. The following provides relevant detail pertaining to our visibility impact analysis of Auxiliary #1 Boiler:

- Enviroplan utilized Calpuff version 6.112 (level 060412) and Calpost version 6.131 (level 060410). These are the model versions used by WRAP-RMC and GVEA in their respective modeling evaluations. For purposes of project expediency and consistency, the Department obtained the executable files for each of these programs from GVEA's consultant, CH2M Hill. CH2M Hill also provided the 2002 hourly ozone data recorded at the Denali National Park (DNP) Castnet monitor, which was used by WRAP-RMC in their analysis (i.e., http://pah.cert.ucr.edu/aqm/308/bart/calpuff/calpuff_inps/ak/).
- The Department provided the 2002 Calmet meteorological data file to Enviroplan on external hard-drive. This file was used by GVEA in their modeling evaluation; and Enviroplan used this meteorological data in this analysis.
- Enviroplan used the Calpuff input file for the Auxiliary Boiler #1 baseline scenario, as previously provided to the Department by GVEA (i.e., "healy02.inp"). Enviroplan revised the Auxiliary Boiler #1 NO_x and SO_2 emission rates consistent with those rates specified in the Department's March 16, 2010 Informal Review document (see table below). The particulate emission rate for Auxiliary #1 Boiler in this revised modeling analysis remains unchanged at 0.8 lb/hour (i.e., unchanged from the GVEA/WRAP-RMC modeling).

Auxiliary #1 Boiler Modeled Scenario	SO_2 Modeled Emission Rate (lb/hr)	NOx Modeled Emission Rate (lb/hr)
GVEA Calpuff Analysis*	0.0056	0.0016
Enviroplan Revised Calpuff Analysis	5.6	1.6

*Generally consistent with the WRAP-RMC Calpuff input file for Auxiliary #1 Boiler, except WRAP used pollutant emission rates expressed in units of grams/second (g/s). Converting the above lb/hour emission rates to equivalent g/s results in relatively low numbers that were reflected in the WRAP Calpuff input file as zero NO_x/SO_2 emission rates for this unit.

- Aside from the emission rate revisions indicated above, Enviroplan used all Calpuff model option settings established by GVEA (based on GVEA's use of the WRAP visibility modeling protocol).
- Enviroplan used the Calpost input file for the Auxiliary #1 Boiler baseline scenario, as previously provided to the Department by GVEA (i.e., "caldena.inp"). Except for the Input Group 1 parameter, **NDRECP**, Enviroplan did not alter any model option setting or input parameter established by GVEA (based on GVEA's use of the WRAP visibility modeling protocol). The revision to **NDRECP** is discussed in more detail below.
- The DNP modeling receptor grid used by GVEA (and WRAP) in their modeling analysis was developed by the National Park Service. While GVEA correctly predicted Calpuff pollutant concentrations at all 1367 receptors, they inadvertently omitted the first 776 receptors of the full 1367 receptor listing from their Calpost analysis. As such, Enviroplan corrected GVEA's Calpost **NDRECP** option to include all 1367 receptors in the revised Auxiliary #1 Boiler visibility modeling. The revised results presented above reflect all 1367 DNP receptors.

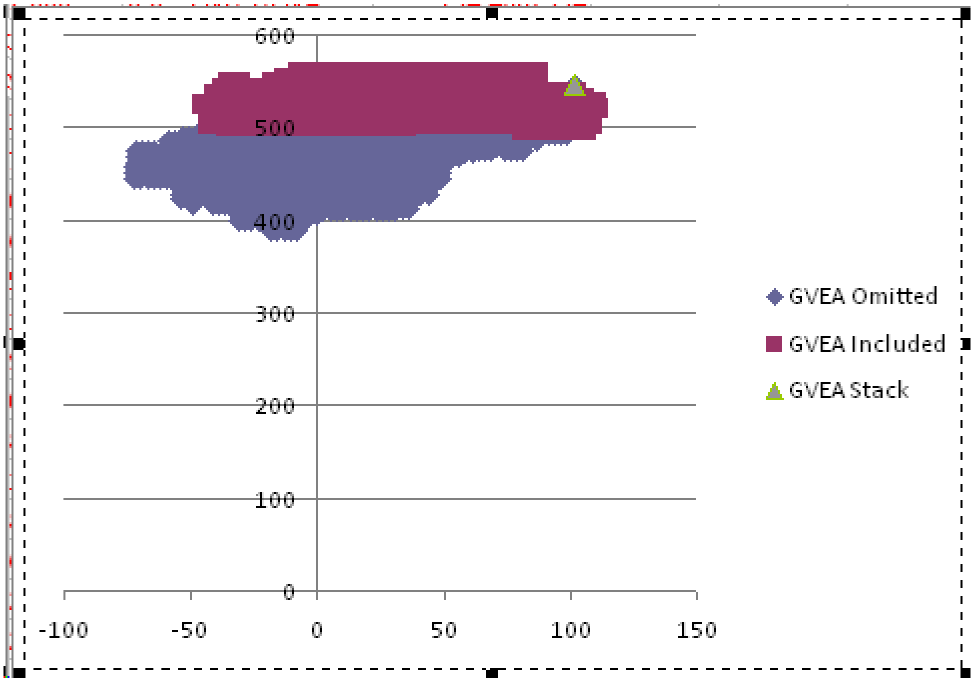
Based on the information described above, Enviroplan determined the revised maximum visibility impact (daily delta deciview, dv) attributable to Auxiliary #1 Boiler. The following presents a comparative summary of the Auxiliary #1 Boiler visibility prediction results:

Auxiliary #1 Boiler Modeled Scenario	Maximum Predicted Visibility Change (Daily Delta-Deciview) (dv)	Significant Change in Visibility* (dv)
GVEA Calpuff Analysis	0.067	0.5
Enviroplan Revised Calpuff Analysis	0.158	0.5

*18 AAC 50.260(q)(4)

The maximum modeled visibility impact associated with Auxiliary #1 Boiler using corrected maximum NO_x and SO_2 emission rates continues to show this emission unit is not predicted to cause or contribute to visibility impairment at DNP.

It is noted that the Auxiliary #1 Boiler revised maximum visibility impact presented above occurred at a location included in GVEA's visibility modeling analysis. Therefore, the revised maximum impact is attributable solely to the corrected unit NO_x and SO_2 emission rates. The 776 previously omitted receptors are relatively distant from the Healy Power Station, and the 591 receptors initially modeled by GVEA are located in relatively close proximity to the plant and remain the dominant receptors in this analysis. The figure below shows the locations of these groups of receptors relative to the Healy Power Station.



While this analysis has focused on GVEA's Auxiliary #1 Boiler, GVEA's omission of the 776 receptors may affect their prior visibility modeling for Healy Unit 1. GVEA omitted the same 776 receptors from the Healy Unit 1 Calpost input files. As such, Enviroplan conducted revised Calpuff/Calpost modeling of Healy Unit 1. The analysis was limited to the GVEA Healy 1 baseline configuration (i.e., maximum daily NO_x, SO_2 and PM emission rates) scenario. Enviroplan corrected GVEA's Calpost **NDRECP** option to include all 1367 receptors; and no other changes were made to GVEA modeling files.

GVEA previously predicted the maximum visibility impact of Healy 1 (591 receptors) to be 3.359 dv. (see GVEA's January 2009 BART determination report; and Sections 7.4 and 8.1 of the GVEA BART Final Determination Report). For the full 1367 DNP receptor grid, Enviroplan determined the maximum visibility impairment attributable to Healy 1 to be unchanged at 3.359 dv.

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF AIR QUALITY
AIR PERMITS PROGRAM

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Return Receipt Requested

February 9, 2010

Kristen DuBois
Golden Valley Electric Association
P.O. Box 71249
Fairbanks, AK 99707-1249

Dear Ms. DuBois:

This letter transmits the Alaska Department of Environmental Conservation's (Department) final Best Available Retrofit Technology (BART) determinations under 18 AAC 50.260(e)-(l) for BART eligible units. The Department determines the following emission rates represent BART for the BART-Eligible emission units at the Healy power plant:

Healy Unit 1

- For Nitrogen Oxides (NO_x), an emission rate (measured as NO_2) of 0.20 lb/MMBtu (30-day rolling average).
- For Sulfur Dioxide (SO_2), an emission rate of 0.30 lb/MMBtu (30-day rolling average).
- For Particulate Matter (PM), an emission rate of 0.015 lb/MMBtu (based on compliance source testing).

Auxiliary Boiler #1

- For Nitrogen Oxides (NO_x), an emission rate (measured as NO_2) of 0.000154 lb/MMBtu (30-day rolling average).
- For Sulfur Dioxide (SO_2), an emission rate of 0.00054 lb/MMBtu (30-day rolling average).
- For Particulate Matter (PM), an emission rate of 0.8 lb/hour (at full load).

The monitoring, recordkeeping, and reporting needed to demonstrate compliance with these emission limits are as recommended in Section 9.2 of the enclosed Final BART Determination Report.

Background

The Department published a preliminary BART determination[1] on May 12, 2009 and accepted public comments through June 15, 2009. The Department received comments from GVEA; Frank Abegg, Fairbanks; Alaska State Representative Mike Kelly, Fairbanks; Don Shepherd, National Park Service; and Sanjay Narayan, Sierra Club. As a result of these comments and information submitted in support of the comments, the Department revised its preliminary decision. The enclosed Response to

[1] Documented in an April 27, 2009, Findings Report.

Comments document explained the Department's evaluation and its use of the comments received. Based on its evaluation, the Department produced the enclosed the Final BART Determination Report[2], dated January 18, 2010. You can find a copy of all comments received, a copy of the April 27, 2009 findings report, and copies of the enclosed documents on the Department's website at: http://dec.alaska.gov/air/gveabart.htm.

Next steps
The Department must include all BART determinations in Alaska's Regional Haze State Implementation Plan (Regional Haze SIP), per Section 169A of the Clean Air Act. The Regional Haze SIP, including the Department's BART determinations, is subject to additional public comment and approval by the U.S. Environmental Protection Agency (EPA) as follows:

First, the Department must submit its Regional Haze SIP proposal to Federal Land Managers (FLMs) for comment. After considering the FLM comments, the Department must provide a public notice and accept public comments for at least 30 days. After considering the public comments the Department will propose its final Regional Haze to EPA for review and approval. During this process the Department will reopen this BART decision, if necessary, to address comments from FLMs, the public, or EPA, to produce a final, federally-approved, Regional Haze SIP. Therefore, this BART decision is not a final Department decision until the Department adopts a final Regional Haze SIP.

Appeal Rights
Any person who disagrees with this decision may request an adjudicatory hearing in accordance with 18 AAC 15.195- 18 AAC 15.340 or an informal review by the Division Director in accordance with 18 AAC 15.185. Informal review requests must be delivered to the Division Director, 410 Willoughby Avenue, Suite 303, PO Box 111800, Juneau, AK 99811-1800, within 15 days of the decision. Adjudicatory hearing requests must be delivered to the Commissioner of the Department of Environmental Conservation, 410 Willoughby Avenue, Suite 303, Juneau, Alaska 99801, within 30 days of the decision. If a hearing is not requested within 30 days, the right to appeal is waived. If a hearing is granted, it will be limited to the issues related to this decision. You are reminded that even if a request for an adjudicatory hearing has been granted, all terms and conditions remain in full force and effect. More information on how to appeal a Department decision is available at http://www.dec.state.ak.us/commish/ReviewGuidance.htm.

Sincerely,

John F. Kuterbach
Program Manager

Enclosures: Final BART Determination Report; Department Response to Comments

Cc (without enclosures; please see webpage referenced in letter for documents):

[2] April 27, 2009 Findings Report revised consistent with the Department's evaluation of comment.

Kate Lamal, GVEA
Sandra Silva, U.S. Fish and Wildlife Service
Representative Mike Kelly, Fairbanks
Frank Abegg, Fairbanks (via e-mail)
Don Shepherd, National Park Service (via e-mail)
Sanjay Narayan, Sierra Club (via e-mail)
Steve Body, EPA, Region 10 (via e-mail)
Herman Wong, EPA, Region 10 (via e-mail)
Tim Allen, U.S. Fish and Wildlife Service (via e-mail)
Bud Rice, National Park Service (via e-mail)
Bruce Polkowsky, National Park Service (via e-mail)
John Notar, U.S. Fish and Wildlife Service (via e-mail)
John Vimont, National Park Service (via e-mail)
Andrea Blakesley, National Park Service, Denali (via e-mail)
Ann Mebane, U.S. Forest Service (via e-mail)
David Mott, U.S. Forest Service, Alaska Region (via e-mail)
Mike Hirtler, Enviroplan Consulting (via e-mail)
Tom Turner, ADEC/APP (via e-mail)
Alan Schuler, ADEC/APP (via e-mail)
Cynthia Wiliams, ADEC/ANP&MS (via e-mail)
Rebecca Smith, ADEC/APP (via e-mail)

Response to Public Comments
Golden Valley Electric Association (GVEA)
Best Available Retrofit Technology (BART) Determination
Response to Comments
January 15, 2010

Prepared by:
Enviroplan Consulting
Tom Turner
Rebecca Smith
Alan Schuler

In accordance with 18 AAC 50.260, the Alaska Department of Environmental Conservation (the Department) public noticed a proposed preliminary April 27, 2009 BART determination findings report for Golden Valley Electric Association's (GVEA) Healy Power Plant on May 12, 2009. This document responds to comments received during the public comment period.

Overview: GVEA submitted a BART control analysis in July 2008 to meet the requirements of 18 AAC 50.260(e) through (h). The BART eligible units at the source consist of one primary power generating unit, the 25-MW Foster-Wheeler Unit No. 1 (Healy 1), and one Cleaver Brooks standby building heater.

The Department contracted with Enviroplan to conduct a technical review of the GVEA BART control analysis. The July 2008 GVEA analysis report was revised and resubmitted by GVEA in January 2009; GVEA provided additional relevant supplemental information on March 18, 24 and 30, 2009 and June 19, 2009.

Enviroplan recommended preliminary BART determinations for each BART-eligible source at this facility, consistent with 18 AAC 50.260(j). Their recommendations were described in an April 27, 2009 "Findings" report, which concluded that the GVEA BART control analysis complied with 18 AAC 50.260(e) through (h); and it recommended BART for Healy 1 as the existing dry sorbent injection system (SO_2); the addition of a SCR system (NO_x); and the existing reverse gas baghouse system (PM_{10}). For Auxiliary Boiler #1, the existing configuration, which is no air pollution control systems, was recommended as BART.

The Department reviewed, accepted and public noticed Enviroplan's recommended preliminary BART determinations, as described in their April 27 Findings report. The Department accepted public comments from May 12, 2009 until June 15, 2009.

This document provides the Department's response to the comments received during the public comment period. The Department asked Enviroplan to incorporate the decisions in this Response to Comment document into their BART Determination Report regarding Golden Valley Electric Association's Healy Power Plant. This allows for consistency between the final decision documents. **The Department therefore considers Enviroplan's Final BART Determination Report as a valid description of the**

technical basis for the BART emission limits established under 18 AAC 50.260(l) for Healy #1 and Auxiliary Boiler # 1.

Comments received:

The Department received written comments from the following by the June 15, 2009 deadline:

A) Frank Abegg, Fairbanks
B) Alaska State Representative Mike Kelly, Fairbanks
C) Don Shepherd, National Park Service
D) Sanjay Narayan, Sierra Club
E) Kristen DuBois, GVEA

Further, on June 19, 2009 Kristen DuBois with GVEA submitted additional information to support the economic analysis summary contained in Attachment 3 of their June 15, 2009 comments. As necessary, this document responds to the additional information received from GVEA on June 19, 2009.

Comments received on the proposed preliminary BART determination reflected two general categories as follows:

A) The proposed determination is not stringent enough; or
B) The proposed determination is too stringent and will be economically infeasible to implement.

Comments from the Sierra Club and the National Park Service (NPS) focused on the preliminary determination being not stringent enough and requested that ADEC require more stringent and additional controls on the Healy Power Plant.

Comments from Mr. Frank Abegg, Representative Mike Kelly, and GVEA focused on the proposed determination being too stringent and too expensive to implement, particularly given that the burden will fall on the utility's rate payers.

Response to Comment Format:

This document contains the comments provided by each party specified above and the Department's response to each comment. Where practicable, a comment is reiterated verbatim; however, most of the comments along with reference to related support information are paraphrased. The Department's responses are shown in bold italics following each comment.

<u>Comments received by the Department on June 12, 2009 from Mr. Frank Abegg</u>

1. Comment (page 1 of letter, 3rd paragraph): Commenter indicates that the May 12, 2009 public notice specifies that the NPS is requiring selective catalytic reduction (SCR) equipment be installed at Healy Unit 1 to control NO_x emissions, along with increased sorbent injection to control SO_2 emissions.

   ***Response from the Department**: The public notice indicates the Department has made a preliminary BART determination for NO_x and SO_2 (and PM) emissions control at Healy Unit 1. The Department is responsible for the establishment of* *emission limits under the regional haze and BART rule, not the NPS. This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.*

2. Comment (page 1 of letter, 4th paragraph): Commenter indicates visibility modeling performed by the Western Regional Air Partnership (WRAP) showed predictions inside the Denali National Park and Preserve (DNPP) in excess of a significance metric of 0.5 deciviews and, based on this modeling, Enviroplan concluded (in the April 2009 Findings Report) that Healy 1 BART controls currently comply with 18 AAC 50.260 (i.e., Alaska regional haze and BART guidance rule). Commenter also indicates "at the insistence of the NPS, Enviroplan stated that an SCR unit should be added to the boilers' existing low NOx burner (LNB) and over-fire air (OFA) system…"

   ***Response from the Department**: The following two points of clarification are made.*

   First, the Findings Report was reviewed and approved by the Department and represents the Department's preliminary determination for GVEA BART. Enviroplan did not conclude, based on the WRAP modeling, that Healy 1 BART controls currently comply with 18 AAC 50.260. As described in Section 7 of the Findings Report, GVEA conducted visibility modeling independent from the WRAP modeling. Except as otherwise indicated in the Findings Report, the modeling was performed in accordance with 18 AAC 50.260 and 40 CFR 51, Appendix Y. The results of the GVEA modeling, along with other prescribed elements of the 5-Step BART determination process of 40 CFR 51, Appendix Y, which are described in Section 2 of the Findings Report, were considered when determining preliminary BART for Healy 1 and not the WRAP modeling results.

   Second, at no time during the preliminary determination process did the NPS "insist" that the Department or its contractor, Enviroplan, require SCR be added to Healy 1. As discussed in the Section 1 of the April 2009 Findings Report (and other report sections), the Department apprised the NPS and GVEA during February 2009 of the then draft preliminary BART findings for Healy 1. Initial comments were received by the Department from the NPS on February 12, 2009. In March 2009, composite cost data and BART determination summaries compiled by the NPS for multiple other BART eligible sources in the Western U.S. were also received by the Department. The Department similarly received initial comments from GVEA during February 2009; as well as relevant follow-up information, including ratepayer data, sorbent invoice data, and other information, from GVEA during March 2009. As discussed throughout the Findings Report, all NPS and GVEA data have been considered in accordance with the BART review procedures of 40 CFR 51, Appendix Y. Only the BART review procedures of 40 CFR 51, Appendix Y, along with the GVEA and NPS submitted information, have been considered in the findings review, and no directive of the NPS (or any other party) has resulted in the preliminary determination reflected in the Findings Report.

   This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

3. Comment (page 2 of letter, 2nd paragraph): Commenter indicates that GVEA's 3/18/09 submittal (pertaining to increased ratepayer costs associated with BART SO_2 and NO_x controls) will require a 3.3% rate increase to pay for the "NPS mandate".

   ***Response from the Department**: As indicated in Response 2 above, the preliminary BART determination is not a result of an "NPS mandate". The BART determination is in response to the visibility protection requirements of the Clean Air Act, Sections 169A and 169B; related codified Regional Haze Rule requirements contained at 40 CFR 51.300 through 51.309 (including 40 CFR 51, Appendix Y); and State of Alaska rule 18 AAC 50.260.*

   Section 6.3 of the Findings Report discussed the potential cost increase to a residential ratepayer based on installation of SCR and increased sorbent injection. The 3.3% increase noted by the commenter is a total increase computed by GVEA for both control systems based on only non-fuel annual costs. As explained in Section 6.3, since BART is a pollutant specific regulatory program the cost impact of each control system must be determined separately for BART determination purposes, rather than cumulatively.

   Sections 6.1 and 6.2 of the Findings Report explain that the respective capital costs associated with SCR and increased sorbent injection provided by GVEA were revised by Enviroplan. These revised costs were utilized in the ratepayer analysis discussed in Section 6.3. Detailed comparisons of ratepayer increases (versus 2008 ratepayer costs) were shown in Tables 6-3-1 through 6-3-4. As indicated in Section 6.3 of the Report, GVEA did not include fuel costs in their comparative metric when assessing the ratepayer increase. This is a direct cost born by each ratepayer and its exclusion will lead to a bias (overstatement) in the percent increase computed in this analysis. As such, Enviroplan utilized the actual annual average 2008 ratepayer cost provided by GVEA to determine the percent ratepayer increase due to the SCR and increased sorbent injection control systems. Use of the 2008 ratepayer cost, which includes fuel and non-fuel charges, resulted in a potential ratepayer increase of 0.70% and 0.43% for the SO_2 and NO_x control systems, respectively.

   This response is provided for the purpose of clarification and it does not change the conclusions of the April 2009 Findings Report. However, as explained later in this document the ratepayer analysis has been revised to reflect GVEA comments (see GVEA comments/responses section herein).

4. Comment (page 2 of letter, 4th paragraph which carries onto page 3 of the letter): The commenter provides a brief historical summary of the Healy Clean Coal Project (HCCP) noting GVEA's receipt of construction permit approval in 1994; operation of a visibility monitoring program (VMP) which ran from December 1997 until May 2000 and included photographic, meteorological parameter and pollutant measurement monitoring at three sites; and installation in 1998 of Healy 1 NO_x controls (low NO_x burners and over-fire air (LNB/OFA)) and SO_2 controls (dry sorbent injection system). Based on the operation of the VMP, and the reduction in NO_x and SO_2 emissions due to Healy 1 controls, the commenter indicates he is not aware of any formal complaints associated with plume visibility impact or regional haze at Denali caused by Healy 1.

***Response from the Department**: Section 7.3 of the Findings Report provided a detailed overview of the GVEA VMP cited by the commenter. The Findings Report acknowledges the data collected during the VMP and the general results of the program, including no formal indication by the NPS or the Department of visible plume impacts from Healy 1 at the DNPP. This notwithstanding, Section 7.3 of the April 27 Findings Report also specifies the reasons that the general lack of complaints associated with the prior VMP does not satisfy the BART rule requirement for visibility modeling. This includes the fact that the visible impact modeling is conducted over a much larger geographic area (i.e., within all of DNPP) than the three locales represented in the VMP, and it considers the potential for haze throughout the park rather than the presence of an individual visible coherent plume as reflected in the VMP (i.e., plume blight). The modeling does not simply account for surface based transport, as suggested by the commenter with respect to valley orientation and dominant low-level wind direction, but instead it considers the effects of three-dimensional meteorology on plume transport and dispersion. More importantly, the BART rule does not provide an exemption from visible impact modeling regardless of the existence of visibility monitoring.*

This response is provided for purposes of clarification and it does not change the conclusions of the Findings Report.

5. Comment (page 3 of letter, 2nd, 3rd and 4th paragraphs of the letter): The commenter cites two documents that he reviewed wherein a discussion is provided on DNPP pollutant monitoring results and the basis for regional haze at DNPP. Based on these reports, the commenter attributed regional haze at DNPP to Arctic Haze, the long-range international transport of related aerosols, and area wildfires. The commenter notes the report on Artic Haze did not identify the Healy Power Plant as causing haze or impacting visibility within DNPP, and indicates the Plant is insignificant in comparison to natural and other "world sources" of emissions that cause haze in DNPP. As such, the commenter believes any reductions in NO_x or SO_2 from installing SCR or increasing sorbent injection would have no "noticeable" impact on visibility inside DNPP.

   ***Response from the Department**: The Department disagrees with the commenter's conclusions. Section 7.3 of the April 27 Findings Report provided a discussion on DNPP pollutant monitoring data, which is more current than the 1999 monitoring report summary cited by the commenter. Also, Section 7.3 of the Report provided a discussion on a final (rather than a draft) Department document pertaining to regional haze in Alaska. As indicated in Section 7.3 and based on available reviewed documentation, the Department agrees with the commenter that Arctic Haze is a contributor to regional haze at DNPP (even though the park is located in the sub-Arctic). However, also as indicated in Section 7.3, local anthropogenic emission sources exist at and around DNPP, e.g., Healy Power Plant, and such sources can potentially contribute to visibility impairment at DNPP. As specified in the BART rule, a source that can "reasonably be anticipated to cause or contribute to visibility impairment at a Class I area" is required to evaluate source emissions for BART control. Therefore, while the commenter notes that one of the reviewed reports did* *not specifically cite Healy 1 as causing regional haze at DNPP, an emission unit is still subject to BART control evaluation if it reasonably contributes to regional haze at a Class I area.*

As explained in Section 7.3 of the April 27 Findings Report, GVEA's visibility modeling of Healy 1 demonstrated a significant contribution to visibility impairment at DNPP. Further, as discussed in Section 7.4 of the Report, GVEA's visibility modeling of Healy 1 with SCR installed resulted in a predicted significant improvement in visible impacts at DNPP (visibility modeling of increased sorbent injection did not demonstrate a significant improvement in visible impacts at DNPP). Therefore, the Department does not agree with the commenter's indication that reductions in NOx likely will have no noticeable impact on visibility at DNPP, as the predicted improvement has been shown to be significant (i.e., at or above 0.5 deciviews).

This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

6. Comment (page 3 of letter, 4th paragraph which carries onto page 4 of the letter): The commenter suggests the regulatory agencies improve their management of forest fire suppression within Alaska to improve visibility and regional haze within DNPP.

   ***Response from the Department**: The comment is acknowledged. However, forest fire suppression is beyond the scope of the state and federal BART rule. No changes are made to the Findings Report due to this comment.*

7. Comment (page 4 of letter, 2nd paragraph): The commenter suggests the cost for installation of SCR to be prohibitive, and the existing NO_x emission limit for Healy 1 to be comparable to the BART limits for other similar sized power plants.

   ***Response from the Department**: A detailed discussion of the cost analysis and comparative cost metrics for SCR was provided in Section 6.1 of the Findings Report. However, as explained in the response to GVEA comments section of this document, revised site-specific cost information has been provided by GVEA. The related cost analysis for Healy 1 has been revised (see GVEA comments section and the revised cost summary at the end of this document).*

   With respect to the comment pertaining to the Healy 1 NOx emission limit, it is emphasized that each BART-eligible unit must be evaluated for potential control in accordance with the 5-Step process prescribed at 40 CFR 51, Appendix Y. This requires a case-by-case consideration of costing, proximity of an affected unit to the Class I area, and visible impacts and related improvements through retrofits. Such considerations are different from affected plant to affected plant. While BART related information for other plant determinations has been considered in the review, visibility modeling of Healy 1 (required by the BART rule) does demonstrate a significant visibility improvement at an emission rate achievable with SCR (i.e., 0.07 lb/MMBtu). Therefore, no changes are made to the conclusions of the April 2009 Findings Report due to this comment.

8. Comment (page 4 of letter, 3rd paragraph): The commenter indicates the use of ammonia, which is used within the SCR control system, will likely result in some atmospheric emissions (i.e., ammonia slip) that could cause increased haze at DNPP. The commenter further speaks to the risk of an ammonia release during material transport and storage at the plant.

   ***Response from the Department**: The Department agrees that the potential does exist for ammonia slip when operating a SCR control system. This situation is well documented in practice, as acknowledged at Section 3.1 of the Findings Report for Selective Catalytic Reduction (SCR). This notwithstanding, the potential for such emissions was not quantified by GVEA, nor was the potential impact on visibility considered in the GVEA modeling protocol or modeling demonstration. Therefore, no further considerations on the potential effects of ammonia slip emissions were considered in the Healy 1 visibility modeling at DNPP. This is indicated in Section 8.1, Item 9 of the Findings Report.*

   Regarding the comment on risk associated with ammonia handling (and storage) Ammonia is considered by EPA to be a hazardous substance, e.g., 40 CFR Part 68. The BART rule provides for the consideration of non-air quality environmental impacts when considering various retrofit options, as discussed in Section 6.1.3 of the Report. While GVEA provided only limited discussion on this aspect of the SCR system, the risk posed by the handling of this material is acknowledged. However, since ammonia is a widely used material in industrial applications industrial safeguards and procedures, such as those required and prescribed by 40 CFR Part 68, can be implemented by GVEA in order to minimize risk from SCR ammonia use.

   As indicated in Section 8.1 of the April 27 Findings Report, the NO_x reductions and visibility improvements associated with the installation of SCR on Healy 1 comport with the requirements of the BART rule, even when considering the possible environmental impact of the ammonia associated with the SCR. Therefore, no changes are made to the conclusions of the April 2009 Findings Report due to this comment.

9. Comment (page 4 of letter, 4th paragraph): The commenter indicates non-support of increased sorbent injection as SO_2 BART for Healy 1 based on relatively high costs, inherent low sulfur content of Usibelli Mine coal, and uncertain improvement in haze or visible impacts at DNPP.

   ***Response from the Department**: Based on the respective cost effectiveness and visibility modeling results presented in Sections 6 and 7 of the Findings Report, the Department agrees with the commenter and has recommended SO_2 BART for Healy 1 as the existing dry sorbent injection system. No changes are made to the conclusions of the April 2009 Findings Report due to this comment. However, based on comments received from the Sierra Club and GVEA as presented later in this document, the cost analysis for increased sorbent injection has been revised (see the respective comments sections and cost summary revision at the end of this document).*

10. Comment (page 4 of letter, 5th paragraph): The commenter reiterates that the proposed preliminary BART emission limits (i.e., SCR) would substantially increase the financial burden on the operation of the Healy Power Plant and their customers.

    Response from the Department*: See Responses 3 and 7 above. There are no changes to the Findings Report due to this comment.*

11. Comment (page 5 of letter, 1st paragraph): The commenter indicates that for decades the NPS has had serious fugitive dust emissions problems inside DNPP in association with vehicle travel on unpaved DNPP roads, and references a NPS document pertaining to this issue. The commenter requested the status of what the NPS is doing to resolve this problem and reduce likely related visibility problems.

    Response from the Department*: The Department is responsible for setting the BART eligible unit emission limits. Conversely, the NPS is responsible for the administration of the DNPP and activities therein. As such, this query must be submitted to, and responded by, the NPS. This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.*

Comments received by the Department on June 12, 2009 from Alaska State Representative Mike Kelly (House District 7)

1. Comment (page 1 of letter, 1st paragraph): The commenter indicates that the (BART) emission limits were proposed by the NPS; SCR installation and increased sorbent injection are being proposed by ADEC for Healy 1; and these control requirements ignore permitting aspects associated with HCCP (approved for permitting in 1994).

   ***Response from the Department**: The Department and not the NPS is responsible for establishing emission limits for BART-eligible units. The preliminary BART retrofit option proposed by the Department in the April 27 Findings Report for Healy 1 NOx control is SCR as indicated by the commenter. However, for SO_2 emissions control at Healy1 the Department proposed the existing FGD system configuration as BART, not an increased sorbent injection system. Further, HCCP was not specifically considered in the BART review for Healy 1 since HCCP is not a BART affected emission unit; however, indirect consideration was done through review of the VMP and related materials (see Response 4 to comments from Mr. Abegg).*

   This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

2. Comment (page 1 of letter, 2nd paragraph): The commenter indicates that the control costs are prohibitive; will not result in a discernable visibility benefit; and the retrofits are disingenuous given the prior (late-1990's, early 2000's) control retrofit to Healy 1 in response to the HCCP approval.

   ***Response from the Department**: The cost effectiveness of SCR was determined in the April 27, 2009 Findings Report not to be cost prohibitive (see Responses 3 and 7 to the preceding set of comments). A predicted significant improvement in visible impacts has been demonstrated (through modeling) when installing SCR on Healy 1 (see Response 5 to the preceding set of comments). The BART retrofit options are not considered to be disingenuous with respect to the regional haze program and BART rule since existing source controls are reflected in the baseline emission rates for both the BART costing analysis (see Section 6 of the Findings Report) and the visibility modeling analysis (see Section 7 of the Findings Report). As such, the existing Healy 1 control systems are accounted for in the BART determination review and findings.*

   While this comment does not change the conclusions of the April 2009 Findings Report, GVEA comments received by the Department included a revised site-specific costing analysis for the SCR control system. The SCR costing analysis has been revised accordingly (see GVEA comments section herein) in the Final BART/GVEA Determination Report.

3. Comment (page 1 of letter, 2nd paragraph): The commenter indicates that the initial capital costs for the proposed retrofit controls (SCR) would be in the millions of dollars; the costs would be borne by the GVEA Co-op customers and would be a significant energy cost increase; and, in essence, requests the NPS and EPA be told the proposal is excessive in light of the cost and existing plant controls.

***Response from the Department**: The final BART determination is made by the Department and not by the NPS and/or EPA, in accordance with the BART rule and 18 AAC 50.260. The preliminary BART determination for Healy 1 is predicated on information provided by GVEA and the regulatory requirements of the regional haze program/BART rule, both of which were detailed in the April 27 Findings Report. Comments made by all parties to the preliminary BART determination, including those of the NPS and EPA, must be considered and addressed as part of the review and determination process (18 AAC 50.260(k) and (l)).*

Section 6 of the April 27 Findings Report did acknowledge the initial capital cost for the proposed SCR control system, and these initial costs were considered in the preliminary BART determination. Further, the annual average incremental cost increase to the system's residential ratepayers was considered and shown to be less than a 1% increase for installation of SCR (see Response 3 to the preceding set of comments), which was not deemed as a prohibitive cost increase.

This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

4. Comment (page 1 of letter, 3rd paragraph which carries onto page 2 of the letter): The commenter indicates that prior retrofit controls were installed on Healy 1 to offset new emissions from HCCP; the plant uses the lowest sulfur coal in the U.S.; special cameras located in DNPP registered no negative (visible) impact; reports issued by ADEC on regional haze concluded the likely contributors to haze (in DNPP) are forest fires and international transport; and the same reports do not cite the Healy Power Plant as the cause for haze or decreased visibility in DNPP.

   ***Response from the Department**: See Responses 1 and 2 above for a related discussion on prior Healy 1 retrofits for HCCP permitting, and the relation to cameras (i.e., the VMP) at DNPP. Also see Responses 4 and 5 to the preceding set of comments (Mr. Frank Abegg) regarding the VMP and contributions to regional haze at DNPP. The use of low sulfur coal at Healy 1 is understood, and the related SO_2 emissions are inherently accounted for in the BART determination through the baseline and retrofit control emission rates provided by GVEA.*

   This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

5. Comment (page 2 of letter, 2nd paragraph): The commenter requests the Department "stand-up" "against the over-reaching NPS when it comes to Healy #1 and HCCP regulation."

   ***Response from the Department**: As indicated in Responses 1 and 3 above, the Department is responsible for establishing emission limits under the regional haze program and BART rule, not the NPS. The NPS, however, can provide comment on the proposed limits. Further, as indicated in Response 3 to the preceding set of comments (Mr. Abegg), the preliminary BART determination is proposed in response to the visibility protection requirements of the Clean Air Act, Sections 169A and*

169B, related codified Regional Haze Rule requirements contained at 40 CFR 51.300 through 51.309 (including 40 CFR 51, Appendix Y), and State of Alaska rule 18 AAC 50.260. Therefore, the Department is legally obligated to comply with these requirements and cannot otherwise obviate these obligations. The preliminary NO_x BART determination for Healy 1 (SCR) reflected in the Findings Report is in response to these same statutory and regulatory requirements.

This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

<u>Comments received by the Department on June 15, 2009, with supplemental information received from Kristen DuBois of Golden Valley Electric Association on June 19, 2009; and on August 27, 2009 in response to an August 17, 2009 Department request for additional information</u>

1. Comment (page 3 of the letter): The commenter indicates the April 27 Findings Report failed to reflect the realities of operating a small coal-fired power plant in the central interior of Alaska and the lack of actual impacts on a Class I area. The commenter also indicates additional potential NO_x control cost information has been provided to the Department, along with further explanation of previously provided information.

   ***Response from the Department**: The content and determinations presented in the April 27 Findings Report considered all information provided by GVEA during the BART evaluation process. This notwithstanding, the comments and information provided by GVEA during the public comment period are considered herein as reflected in the comments/responses for this commenter (below).*

2. Comment (page 3 of the letter, ***The Regional Haze Rule***): The commenter provides an overview of the federal regional haze rule (40 CFR 51.300 to 51.309), the related Appendix Y (*Guideline for Best Available Retrofit Technology Determinations under the Regional Haze Rule*), and the Alaska rule requiring a BART determination (18 AAC 50.260). The commenter concludes that "GVEA believes the proposed preliminary BART for Unit No. 1 is untimely and untenable."

   ***Response from the Department:** The comment is unclear with respect to "untimely and untenable." The timing on the review for, and issuance of, the preliminary BART determination for the Healy Power Plant was conducted in accordance with 18 AAC 50.260. GVEA was notified by the Department during December 2007 of their subjectivity to the rule; the Department conducted two public workshops and one public hearing from January – March 2008; GVEA submitted their initial BART determination during July 2008; additional information submittals and conversations occurred through March 2009; and a preliminary April 27 BART determination was prepared and a 35 day public comment period was public noticed on May 12 2009. In terms of being "untenable", the department and its contractor, Enviroplan, evaluated all information submitted by GVEA in determining preliminary BART for Healy 1.*

   The preliminary BART determination was conducted in accordance with 40 CFR 51, Appendix Y, Section IV (5-step evaluation process), as required at 18 AAC 50.260(e), including the feasibility of various control options and their associated costs. However, as indicated in Response 1 above, additional refined information provided by GVEA during public notice is considered herein (below) in terms of the BART determination for Healy 1.

   This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

3. Comment (page 4 of the letter, ***BART and Healy Unit 1***): The commenter references 40 CFR 51.308(e)(1)(ii)(B), which requires that a fossil-fuel fired power plant having a total rating of greater than 750 MW must follow the procedures found in Appendix Y when determining BART (i.e., the procedures used in the Healy 1 evaluation). The commenter specifies that Healy 1 is only 25 MW. Nonetheless, the commenter does acknowledge Enviroplan's application of Appendix Y in making the preliminary BART determination for Healy 1.

   Response from the Department*: While the Department acknowledges the citation and rated capacity for Healy 1 noted by the commenter, the department notes that 18 AAC 50.260(e) requires the owner/operator to conduct an analysis of control options for an affected source (regardless of type or capacity) consistent with Appendix Y, Section IV. This is the basis for the BART evaluation for Healy 1, as described in the Findings Report.*

   This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

4. Comment (page 4 of the letter, ***BART and Healy Unit 1***): The commenter indicates the use of peak 24-hour emission rates for the visibility modeling pre-control (baseline) scenario, as required by the BART guideline, instead of using annual average emission rates, results in a "distorted" or larger degree of improvement of visible impacts when evaluating various control options. The commenter suggests that the Department has the discretion to consider this situation when considering a BART determination.

   Response from the Department*: The comment pertaining to the Department's ability to use "discretion" when considering the visibility modeling emission rates and impacts is unclear.* ***The regulatory basis for the modeling, as noted by the commenter, is found in the federal BART rule. Additionally, 18 AAC 50.260(h)(2) requires that the visibility impact analysis determine the maximum change in visibility impacts in daily deciviews, between the current or pre-control technology and each potential BART control option. Maximum daily change would not be determined though the use of annual emission rates. The Department is required to determine BART in accordance with the federal and state BART rule, and this is predicated on the use of peak 24-hour emission rates for visibility modeling. Since the use of peak 24-hour emission rates is reflected in the preliminary BART determination, there is no change to the conclusions of the April 2009 Findings Report due to this comment.*

5. **Comment (page 4 of the letter, *BART and Healy Unit 1***): The commenter suggests that Enviroplan was "under pressure" from the NPS when determining BART. The commenter further indicates Enviroplan let the proximal location of Healy 1 to DNPP (i.e., approximately 8km) "hijack" the BART analysis. The commenter also suggests that the BART determination (for NOx) as SCR was predetermined, and that Enviroplan ignored the language of the regulations and the statutory purpose of protecting visibility. Finally, the commenter concludes that Enviroplan's determination was "arbitrary and capricious" as applied to Healy 1.

***Response from the Department*:**
The Department's is responsible for BART determination after a BART control technical analysis for the BART sources. The BART technical control analysis is an open process. Both the NPS and GVEA offered their opinions and information regarding the BART technical analysis; Enviroplan considered all available information in making the recommendation; and the Department likewise considered all available information in making their preliminary decision.

No communication between the NPS and Enviroplan occurred between the start of Enviroplan's contractual obligation to the Department for this project, through public noticing of the April 27, 2009 Findings Report. The proximity of Healy 1 to DNPP is a fact that must be considered within the proscribed procedures of the BART rule. The Department has considered this fact based on the visibility modeling results and other information provided by GVEA. The Department has documented the basis for the decisions made for preliminary BART. It would be "arbitrary and capricious" at best, and remiss and non-compliant with the regulation at worst, for the Department to ignore the cost effectiveness results and degree of predicted visibility improvement at DNPP. The preliminary BART determination for Healy 1 was based solely on the information provided to the Department or to its contractor during this review, including draft determination comments and related additional information provided by, GVEA and the NPS ; therefore, this was not a "predetermined" outcome as claimed by the commenter. There is no change to the conclusions of the April 2009 Findings Report due to these comments.

6. Comment (pages 5 - 8 of the letter, ***NOx - Cost***): The commenter notes a series of potential errors in the April 2009 Findings Report pertaining to Enviroplan's SCR cost assessment for Healy 1 versus that provided by CH2M Hill on behalf of GVEA, based on the following:
    a. CH2M Hill provided cost information based on the use of EPA's CUECost manual[1], supplemented with vendor cost data and proprietary information from other engineering design projects. Enviroplan computed control cost information using generic data and EPA's Cost Manual[2]. It is not clear if Enviroplan accounted for cost escalation from the Cost Manual's 1997 cost basis; regardless, escalation of costs since 1996 is inaccurate. The NPS also stated a preference for use of the Cost Manual in part to provide consistency in BART determinations. CH2M Hill believes its actual experience and approach to CUECost provides a more accurate representation of anticipated SCR costs for Healy 1.
    b. Enviroplan failed to consider the unique costs associated with installation and operation of SCR on Healy 1, including additional insulation, heat tracing, freeze protection, heater enclosures, high Alaska construction costs, higher Alaska materials transportation costs and other factors associated with site remoteness.
    c. Enviroplan's costs failed to scale costs to a 25 MW plant. The commenter suggests the use of an equipment cost capacity adjustment factor of 0.8 (i.e., size

[1] U.S. EPA, *Coal Utility Environmental Cost (CUECost) Workbook User's Manual,* developed for EPA by Raytheon Engineers & Constructors and Eastern Research Group, Version 1, November 1998, with revision February 9, 2000..
[2] U.S. EPA, *EPA Air Pollution Cost Control Manual*, 6th Ed., Publication Number EPA 452/B-02-001, January 2002.

ratio raised to the power of 0.8 to determine comparative cost), based on American Association of Cost Engineers (AACE) published cost capacity factors[3]. The commenter provides a graphic (as Attachment 1 to their June 15 letter) showing the increased cost ($/kW) for a 25 MW plant versus a 100 MW plant, and indicates the Enviroplan cost of $241/kW incorrectly omits the cost escalation for plants less than 100 MW.

d. CH2M Hill's previous economic evaluations were based upon order of magnitude cost estimates (i.e., accuracy of -30% to +50%), which the commenter deems consistent with the BART process since completion of a more detailed cost estimate was not intended or justified for the "BART screening analysis". As such, based on SCR determined as preliminary BART for NOx at Healy 1, a more detailed capital and operating cost estimate has been prepared. GVEA contracted Fuel Tech, a consulting company that specializes in SNCR and SCR application, to inspect the Healy plant; gather additional site-specific data; and more fully assess the capital cost impact associated with a retrofit SCR system designed to meet the 0.07 lb/MMBtu preliminary BART NO_x emission limit. Fuel Tech conducted the evaluation and issued a findings report on June 10, 2009 (Attachment 2 of the commenter's June 15 letter), which in turn allowed GVEA to refine their operating and maintenance (O&M) costs. While the Fuel Tech evaluation was not a detailed engineering study and cost analysis, it did account for actual current systems setup and plant retrofit design limitations and requirements. Fuel Tech indicates no SCR retrofits have been made in the U.S. on coal-fired boilers as small as Healy 1. As such, Fuel Tech believes their costing, while based on their current project experience for many other SCR systems on coal-fired boilers, may understate the actual cost to construct such a system on Healy 1.

e. CH2M Hill utilized the refined Fuel Tech and GVEA cost data to revise the BART economic analysis previously submitted for Healy 1, as summarized in Section 6 of the April 27 Findings Report. Aside from the revised capital and operating costs, the revised analysis includes an 8-year amortization scenario (in addition to the 15-year control equipment lifetime scenario) to account for the expected remaining useful life of Healy 1, as allowed pursuant to the BART rule (40 CFR 51, Appendix Y, IV.D.k.1). The commenter indicates that Enviroplan did not take into consideration the fact that the estimated remaining useful life of Unit 1 is 15 years. By the time of a 2016 installation (approximately) for an SCR control system, this will leave about 8 years of useful life for Healy 1 and require that an 8-year amortization be applied to the SCR cost analysis.

f. A revised BART economic analysis for SCR based on the Fuel Tech study and the remaining useful life of Healy 1 has been prepared by CH2M Hill. The commenter indicates the revised costs will produce a ratepayer increase of about 3.5% which they deem significant for a small ratepayer base, especially since implementation of the controls will have no effect on improved visibility degradation due to the predominating effects of wildfire events within or impacting DNPP.

[3] English, Lloyd M. & Humphreys, Kenneth K. (1993*), Project and Cost Engineers' Handbook*, Marcell Dekker, Inc. New York.

g. The commenter cites Enviroplan's reference to NPS cost information ($/kW) when considering Healy 1 costs, and suggests the reference to be misleading. The commenter notes there are no other BART eligible units of a capacity comparable to Healy 1. They also cite the ratepayer impact (discussed above); and they reference a May 13, 2009 NPS summary spreadsheet ("*EGUs with BART NOx Controls*") as indicating 42 BART eligible units with only 4 controlled by SCR and only one (375 MW tangentially-fired boiler in Minnesota) as having a 0.07 lb/MMBtu limit. They further indicate the BART rule provides for considering the existence and viability of other similar projects when determining BART. The commenter also makes an additional reference to a concluding statement made by Enviroplan in Section 6.1 of the April 2009 Findings Report (i.e., page 17, final bullet), indicating that statement to be without foundation given that no 25 MW coal fired boilers are subject to BART, particularly those requiring SCR retrofit control technologies in the Arctic.

Response from the Department*: As a general response to this comment, it is noted that a teleconference was held on February 25, 2009 between the Department, GVEA, CH2M Hill and Enviroplan. Among other topics discussed, the Department indicated to GVEA that draft preliminary BART findings for Healy 1 included SCR for NOx control. As a result, GVEA requested the submittal of refined retrofit cost data, including the cost impact of the potential retrofit controls to their residential ratepayer base. The Department agreed to this request; however, given pending SIP submittal time constraints and the amount of time already provided for data submittal, the Department indicated that the retrofit cost refinements should be GVEA's last, best estimate on such data. Although acknowledging this request, GVEA's June 15 and 19, 2009 response to comments again included refined cost information and a new economic evaluation for SCR NOx control at Healy 1. This notwithstanding, the Department is considering the new information in response to this "comment" and final BART/GVEA Determination*

The following specific responses are provided to commenter paragraphs a through g above:

a. In the April 27 Findings Report, the purpose of Enviroplan's use of the Cost Control Manual was to provide a point of comparison between the costs reflected in both the GVEA analysis and the NPS Cost Control analysis, mainly to assess the relative accuracy of the cost of materials and services known to be relatively high in Alaska. The Department does not dispute the use of CUECost for the BART cost evaluation. It is recognized that, unlike the Cost Control Manual, CUECost was specifically developed by EPA to provide order-of-magnitude estimates of installed capital and annualized operating costs for SO_2, NO_x and particulate air pollution control systems to be installed on coal-fired power plants. The cost-basis year default in CUECost is 1998, which is the same as the Control Cost Manual. The Department agrees that current, vendor-based cost data is preferred for use in the cost evaluation analysis, as other recent information suggests both EPA cost tools understate the costs for SCR[4]. The use of contractor-developed site-specific refined

[4] State of Oregon, Department of Environmental Quality, "Agenda Item J, Action Item: 2008 Oregon Regional Haze Plan and new controls for PGE Boardman coal-fired power plant proposed rulemaking", Attachment B, Summary of Comments and DEQ Response, June 18-19, 2009 EQC Meeting.

costs for SCR, as discussed in paragraph d above, are believed to be superior to escalation of older base-year initial assumptions from either EPA program.

b. *The Department understands the need to account for unique costs and considerations associated with installation and operation of the SCR system (and other options) located in the Alaska environment. The site-specific capital cost evaluation and related information provided by GVEA, based on the May 2009 Fuel Tech study, has been considered herein (see additional related discussions below).*

c. *The department and its contractor, acknowledges that the SCR cost information contained in the CUECost manual is most applicable to units with capacities greater than Healy 1. In fact, Section 1.7 of the CUECost manual states "CUECost is designed to produce ROM estimates for a wide range of plant sizes and coal types. However, appropriate ranges of plant size and operating conditions have been established based on the limits to the database used to construct the cost-versus-capacity algorithms. Range limits are provided in the spreadsheet for each input supplied by the user. The major criteria limitation for CUECost is the plant size range. Equipment algorithms are based on the assumption that they will be installed at a facility ranging from 100 to 2000 MW in net capacity." As a point of comparison, the Cost Control Manual, Section 4.2, states "This section presents design specifications and a costing methodology for SNCR and SCR applications for large industrial boilers (greater than 250 MMBtu/hr)". However, Section 4.2, Chapter 2.4 further specifies "The capital and annual cost equations were developed for coal-fired wall and tangential utility and industrial boilers with heat input rates ranging from 250 MMBtu/hr to 6,000 MMBtu/hr (25 MW to 600 MW)". While it is not immediately clear how many (or which) 25 MW coal-fired boilers were included in the Cost Control Manual SCR costing information, it generally seems from the EPA discussion that most (or all) of the information was prepared for units whose capacities exceed that of the 25 MW Healy 1 unit.*

Based on the above, the Department acknowledges the potential inaccuracies associated with the escalation of average costs for an emission unit that is outside the bounds of empirically established cost information. This situation is obviated by the use of the refined site-specific capital costs developed by Fuel Tech. GVEA has included a revised economic analysis for SCR with their June 15 and June 19, 2009 comment letters using the Fuel Tech information.

d. *The Department and its contractor do not agree that the economic evaluation should have been considered as a "BART screening analysis". 40 CFR 51, Appendix Y, Section IV.D,4.a.5 specifies "the cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option." As such, given GVEA's own determination on the viability of SCR as a retrofit option at Healy 1; the related predicted visibility improvement with this option; the cost effectiveness results; CH2M Hill's knowledge of available NPS BART cost summary data; and the consideration of the entirety of this information in the context of the BART review process, the comment on the "BART screening analysis" is unclear. Further, the Department indicated to GVEA during February 2009 that the draft preliminary Healy 1 BART determination for NOx was SCR. While the Department provided additional time for GVEA to further compile and submit information for consideration under the BART review process, it was not* *until June 2009; almost one year after the July 2008 initial BART submittal was received at the Department, a site-specific refinement of SCR costing occurred.*

The above notwithstanding, the Department acknowledges the refined site-specific cost estimate provided by GVEA through their SCR engineering consultant, Fuel Tech. GVEA has revised the economic analysis for Healy 1 based on use of the Fuel Tech results (see related response in paragraph e. below).

e. The commenter specifies "Enviroplan did not take into consideration the fact that the estimated remaining useful life of Unit No. 1 is also 15 years" when considering the likely SCR install date of 2016 (i.e., BART install date of 5-years after final SIP approval, which is estimated to be 2011 (two years after the 2009 submittal date)). The department and its contractor agree with this statement. It is the responsibility of the applicant to reflect such information in their analyses, and not the responsibility of the Department (or its contractor) to refine such analyses.

f. However, it is emphasized that the contractor, Enviroplan, reviewed cost analyses (July 2008, January 2009 and March 2009), provided by GVEA. In all cases, the analyses were based on a 15-year lifetime for an SCR system. The GVEA reports did not attempt to quantify any other (shorter) lifetime periods associated with a reduced Healy 1 remaining lifetime. It is the responsibility of the applicant to reflect such information in their analyses, and not the responsibility of the Department (or its contractor) to refine such analyses.

The above notwithstanding, 40 CFR 51, Appendix Y, Section IV.D.4.k provides for the amortization of costs based on remaining useful life. This citation also provides for flexibility if an affected source does not want to accept a federally enforceable permit condition establishing a shutdown date (i.e., the case for GVEA as per their comments). In such instances, the regulatory agency <u>may</u> include a permit condition requiring controls, if such were deemed as BART in the absence of the contracted amortization period.

GVEA has stated the expected remaining useful life for Healy 1 is 15 years from current (2009); therefore, The Department agrees that GVEA's use of an 8-year amortization analysis for Healy 1 retrofit control systems is consistent with the BART Guideline. At this time, the Department has made no determination about future permit conditions for Healy 1 based on the conditional flexibility provided in the BART Guideline as specified above, and the fact that Healy 1 will be 57 years old in calendar year 2024 (fifteen years from this 2009 findings review). The department and its contractor have considered the revised economic evaluation prepared by CH2M Hill on behalf of GVEA. The SCR system capital costs and related operating and maintenance costs are based on the May 27, 2009 site-specific evaluation conducted by Fuel Tech. While the revised economic analysis includes both 15-year and 8-year boiler lifetime scenarios, the Department has decided that the 8-year lifetime is acceptable and is consistent with the BART Guideline. The revised SCR (and other retrofit option) cost results are summarized at the end of this document.

The department's technical contractor, Enviroplan, has made several corrections to the GVEA cost analysis for SCR as follows. First, a double-counting of the O&M

costs associated with reagent and catalyst replacement has been eliminated (this correction was acknowledged by GVEA on August 27, 2009). Second, GVEA submitted revised SCR NOx cost information for two baseline emission scenarios, 0.28 lb/MMBtu and 0.25 lb/MMBtu, and they indicated the true baseline to be more reflective of 0.28 lb/MMBtu based on a 5-year analysis of 30-day NOx emission rates for Healy 1. Therefore, the revised NOx retrofit option cost analyses presented at the end of this document reflect the use of the 0.28 lb/MMBtu baseline, which is more conservative than the 0.25 lb/MMBtu baseline in terms of the cost per ton of pollutant removed metric.

It is noted that the revised NOx baseline emission rate does not affect the visibility impact modeling since modeling relies on the peak 24-hour pollutant emission rate, not the 30-day rolling emission rate. Therefore, there is no change in modeled visibility impacts and related dollars per deciview improvement cost metrics, except for the use of the 8-year amortization period. Finally, it is noted that GVEA escalated their costs to reflect calendar year 2016, i.e., the first year of SCR operation. However, Enviroplan did not use these escalated costs since the comparative cost metrics would also need to be escalated to 2016. Instead, Enviroplan relied on current costing (2009 dollars for SCR and 2007 dollars for other control options) as provided by GVEA for the revised cost analysis.

The BART rule does not exempt affected sources from considering retrofit controls based on the contribution from other sources, even natural and/or international contributors. With respect to the stated 3.5 percent ratepayer increase, as indicated in Section 6.3 of the April 2009 Findings Report this percentage is reflective of combined proposed costs of SCR and FGD sorbent injection increase. Since visibility impairing pollutants are individually evaluated under the BART rule, the cost associated with these two systems is not considered on an additive basis.

The above notwithstanding, the cost of SCR has been refined based on the Fuel Tech on-site cost evaluation; and the costs for optimized sorbent injection also have been revised (see related response to Sierra Club comments). The April 2009 Findings Report has been revised to reflect these updated cost analyses (also see the summary at the end of this document). Based on the cost revision, SCR is no longer considered as BART for Healy 1. As such, the ratepayer cost analysis tables of the April 2009 Findings Report (Tables 6-3-1 and 6-3-4) have been updated accordingly, as reflected in the revised Findings Report. The Department recognizes the incremental costs associated with the installation of BART retrofit control systems represent cost increases to the GVEA ratepayers. It is further understood that GVEA serves a relatively small rural community[5] that is not connected to a nationwide or outside electric grid or connected to other utilities; electricity rates would be increased to pay for add on emissions controls; and nonetheless, the revised Findings Report potential ratepayer increase of 0.31% and 0.38% for the ROFA (NO_x) and increased sorbent injection (SO_2) control options are not, in and of themselves, deemed to be cost prohibitive in terms of assessing the viability of these systems.

g. *The Department agrees that the Findings Report (Section 6.1, page 17) is ambiguous with respect to the capital cost of the SCR system ($/kW) and available NPS*

[5] *Approximately 36,800 residential customers based on information received from GVEA, March 30, 2009.*

information. The statement was made in reference to a January 9, 2009 data summary compiled by the NPS for western U.S. electric generating units (EGUs). The NPS summary reflected BART evaluation and cost data for SCR systems that were prepared by affected electric generating unit (EGU) sources, and reviewed/adjusted by the NPS. As indicated in Section 6.1 of the April 27 April 2009 Findings Report, based on their summary the NPS determined the range of SCR installed capital costs to be $80/kW - $270/kW. As shown in the revised cost analysis at the end of this document, the revised installed capital cost for SCR is $874/kw. The SCR control option is no longer deemed viable as NOx BART for Healy 1.

The above notwithstanding, the following is noted for purposes of clarification. The NPS disseminated updated BART control survey data spreadsheets on May 13, 2009[6]; and again on August 12, 2009[7]. As shown below, the NPS summary information indicated only four western region EGUs (including Healy 1) with SCR proposed for NOx control, with two units using SCR as reasonable progress.

Operating Company & Facility	Minnesota Power - Boswell Energy Center Unit #3	Xcel Energy – Allen S. King Generating Plant Unit #1	Golden Valley Electric Association (GVEA) – Healy Unit #1	Pacificorp Naughton Unit #3	Pacificorp Jim Bridger Units 3&4	PGE - Boardman
State	MN	MN	AK	WY	WY	OR
Boiler Type	Tangential	Cyclone sub-bituminous	wall-fired, wet bottom	tangential sub-bituminous	tangential sub-bituminous	wall-fired PRB sub-bituminous
Rating (MW Gross)	375	550	25	330	530 (each)	617
Preliminary BART Control	LNB+OFA+SCR	SCR	SCR	LNB+OFA+SCR	LNB+OFA; SCR as reasonable progress (RP)	LNB+OFA; SCR (RP)
30 Day Rolling NOx Emission Limit	0.07 lb/mmBtu	0.10 lb/mmBtu	0.07 lb/mmBtu	0.07 lb/mmBtu	0.26 lb/mmBtu (BART) 0.07 lb/mmBtu (RP)	0.23 lb/mmBtu (BART) 0.07 lb/mmBtu (RP)

As can be seen from the above, none of the EGUs are comparable in capacity to the 25 MW Healy Unit 1. For those EGUs most comparable to Healy 1 (wall-fired EGUs, with capacity in the range 25-100 MW), review of the NPS data indicates the following proposed retrofit determinations:

Operating Company & Facility	Colorado Springs Utilities – Martin Drake Unit # 5	Colorado Springs Utilities – Martin Drake Unit # 6	Golden Valley Electric Association (GVEA) – Healy Unit #1	Nevada Energy - Tracy Generating Station Unit # 1	Nevada Energy - Tracy Generating Station Unit # 2	Nevada Energy - Tracy Generating Station Unit # 3

[6] *NPS BART Evaluation, http://www.wrapair.org/forums/ssjf/bart.html .*

[7] *Email forwarded Don Shepherd, NPS, to various recipients, entitled "Latest Compilation of BART Determinations and Proposals Attached BART Evaluation", dated August 12, 2009.*

State	CO	CO	AK	NV	NV	NV
Boiler Type	Wall fired	Wall fired	wall-fired, wet bottom	Not stated	Not stated	Not stated
Fuel	bit/sub-bit mix	bit/sub-bit mix	sub-bituminous	Pipeline NG & blended Fuel Oil	Pipeline NG & blended Fuel Oil	Pipeline NG & blended Fuel Oil
Rating (MW Gross)	55	85	25	55	83	83
Preliminary BART Control	addition of OFA to existing LNB	addition of OFA to existing LNB	SCR	LNB+FGR	LNB+FGR	LNB+FGR
30 Day Rolling NOx Emission Limit	0.39 lb/mmBtu	0.39 lb/mmBtu	0.07 lb/mmBtu	0.15 lb/mmBtu (annual)	0.12 lb/mmBtu (annual)	0.19 lb/mmBtu (annual)

Based on the two summary tables shown above, Enviroplan agrees with the commenter that there are no NOx SCR BART determinations (proposed or final) for western EGUs similar in capacity to Healy 1. Enviroplan also agrees that NO_x BART generally reflects low NO_x burners with either over fired air or flue gas recirculation for similarly sized units.

Again, the above information notwithstanding, Enviroplan has revised the Findings Report to reflect the new economic evaluation for SCR based on the Fuel Tech site-specific cost evaluation study. The NOx baseline emission rate of 0.28 lb/MMBtu is reflected in the revised cost analysis results, and an 8-year useful lifetime is assumed for Healy 1 for all control options (including SCR). A summary of the revised cost evaluation is found at the end of this document.

7. Comment (page 8 of the letter, ***Energy and Environmental Impacts***): The commenter indicates that, since the April 27 Findings Report already decided SCR to be appropriate for Healy 1, it gave no serious consideration to the energy and environmental impacts associated with an SCR system. The commenter reiterates the SCR system will consume power otherwise available for dispatch to the co-op system customers; and it will result in increased ammonia emissions (slip) as the catalyst efficiency decreases with time. Further, the commenter reiterates the use of ammonia will result in hazardous risk associated with its transport/storage; and result in a solid waste disposal impact due to ammonia accumulation in the ash, which also negates the salability of the ash.

   Response from the Department*: The selection of SCR as preliminary BART for Healy 1 was not pre-determined. The determination was based on information submitted to the Department and evaluated in accordance with state and federal BART rules and the Guideline (40 CFR 51, Appendix Y). Regarding the comment on the energy impact, the comment is unclear since the additional electricity cost for the control system was included in the GVEA cost analysis, in accordance with the BART Guideline (40 CFR 51, Appendix Y, Section IV.D.4.h); the penalty itself has been estimated by GVEA at only 0.44% of potential power output from Healy 1. Regarding ammonia slip, it is agreed that ammonia emissions can have a countervailing impact on visibility versus NOx reduction from the SCR system; however, the comment is qualitative only and cannot be considered further without* *ammonia emissions inclusion in the modeling analysis (which was not done by GVEA).*

Regarding the potential hazards associated with ammonia, the BART Guideline (40 CFR 51, Appendix Y, Section IV.D.4.i) indicates "the fact that a control device creates a liquid or solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to other similar facilities elsewhere and the solid or liquid waste is similar to those other applications." While it is recognized that there are presently no facilities the size of Healy 1 utilizing SCR as BART and storage/transport of ammonia around the sensitive Class I area would be required, it is clear that SCR has relatively wide application on combustion sources for NO_x removal and results in similar waste for these other applications. As noted in response 8 to comments from Mr. Frank Abegg, industrial safeguards and procedures have been established, such as those required and prescribed by 40 CFR Part 68, to minimize risk from hazardous material (e.g., ammonia) use. Further, GVEA could have accounted for the lost revenue associated with ammonia accumulation in the otherwise saleable ash product in their cost analysis, but this was not included. Again, the commenter's concerns are understood and acknowledged, but the qualitative/quantitative information provided by GVEA on the SCR energy penalty and ammonia use did not rule-out SCR as a viable option. While there is no specific change to the Findings Report due to this comment, the revised costing for the SCR option (see end of this document) has resulted in SCR being deemed infeasible for Healy 1.

8. Comment (page 8 of the letter, ***Existing Pollution Control Technology***): The commenter indicates that, due to the fact that Healy 1 already has significant emissions reduction technology in place (for NO_x, SO_2 and PM) deemed as BART for substantially larger EGUs, the preliminary BART determination disregards applicable regulations and "violate[s] the spirit of the Memorandum of Agreement among NPS, GVEA, the Alaska Industrial Development and Export Authority, and the U.S. Department of Energy."[8]

    Response from the Department*: The Memorandum of Agreement did not address future requirements. The BART determination is a case-by-case evaluation of retrofit technology. Existing emission reduction technology factors into this evaluation by reducing the number of additional retrofit technologies available and by reducing the cost effectiveness of adding those retrofit technologies. The Department's evaluation included these factors in its evaluation of the available retrofit technologies.*

    There is no change to the Findings Report due to this comment.

9. Comment (page 9 of the letter, ***Remaining Useful Life***): The commenter indicates the useful life of the plant is relevant in the BART program and must be considered, noting Healy 1 will long be retired by the regional haze program natural conditions deadline of 2064.

[8] *Memorandum of Agreement, Healy Clean Coal Project, Healy, AK, among the U.S. Department of Energy, U.S. Department of the Interior/National Parks Service, AIDEA, and GVEA, dated November 9, 1993.*

***Response from the Department**: The Department agrees that the remaining useful life of Healy 1, which has been indicated by GVEA to be until about 2024, should be accounted for in the BART determination process. Also see response 6 above (and related responses elsewhere in this document). The revised cost results are summarized at the end of this document.*

10. Comment (page 9 of the letter, ***Degree of Visibility Improvement***): The commenter notes a series of issues regarding the expected degree of visibility improvement anticipated from the BART determination, as follows:

    a. The commenter indicates the Findings Report fails to consider the purpose of BART which they note as "namely, the protection and improvement of visibility by addressing sources which have an adverse impact on visibility in Class I Federal areas and to restore visibility to natural conditions by 2064." To this end, the commenter indicates the useful life of Healy 1 will expire long before 2064, and Healy 1 causes no perceptible impact on visibility (at DNPP).

    b. The commenter notes that 40 CFR 51.301 (Definitions) makes reference to the "time of visitor use" portion of the *adverse impact on visibility* definition, noting DNPP is generally not visited for about 8 months of the year. The commenter notes the NPS has not specified a concern or complaint regarding the Healy power plant and visibility impacts at DNPP.

    c. The commenter suggests Enviroplan "dismissed" their prior visibility monitoring program (VMP) and related data, and they have cited a Department report[9] which concludes "the monitoring program produced no evidence of a discolored NO_2 plume or regional haze event associated with the operation of Healy Unit #1." The commenter indicates the previous VMP, including modeling by ADEC and NPS, consistently have shown no impact on visibility.

    d. The commenter has provided a visibility trend graphic for 1989 - 2007, based on data from the IMPROVE monitoring station located at the Park visitor's center. The commenter opines that the effects of the 1996 NO_x and 1999 SO_2 control projects at Healy 1 are not manifested in the trend data; therefore, any visibility impairment at DNPP is not attributable to Healy 1.

    e. The commenter reiterates, based on NPS information[10], that a significant contribution to haze at DNPP is from international contaminant transport to DNPP (Arctic Haze); in-park roadway vehicle dust emissions; and smoke from natural wildland fires (locally and internationally); and that reducing emissions from Healy 1 will add relatively minimal theoretical visibility improvement at DNPP given these other significant sources will continue to impact visibility at DNPP.

    f. The commenter notes the Department should make a determination on statewide reasonably further progress to avoid placing an undue burden on a single source being evaluated under the BART rule.

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[9] Alaska Department of Environmental Conservation, ***"A BART Case Study -Healy Clean Coal Project"***, as Appendix A to WESTAR Council June 2001 report, "RA BART and RA BART-Like Case Studies", located at http://www.wrapair.org/forums/amc/projects/ra_bart_case/Healy-A.doc .

[10] *NPS, May 8, 2009, from http://www.nps.gov/dena/naturescience/upload/airquality2009.pdf.*

g. The commenter concludes that, based on the above comments, SCR as BART will provide no real visibility benefit while resulting in prohibitive costs that must be borne by the customers (i.e., 40 CFR 51, Appendix Y, Section IV.5.E.3.2).

***Response from the Department**: The following specific responses are provided to commenter paragraphs a. through g. above. Unless otherwise indicated, the responses are provided for purposes of clarification and do not change the conclusions of the April 2009 Findings Report.*

a. The Department understands the purpose of BART and generally agrees with the commenter's interpretation of the purpose of BART, including the useful lifetime of Healy 1 as discussed in response 6 above. However, the Department does not agree that BART is intended to consider "adverse" impacts on visibility. The regional haze rule (40 CFR 51.301) defines "adverse impact on visibility" only in the context of regional haze SIP development for New Source Review (i.e., 40 CFR 51.307). By contrast, 40 CFR 50.308(e) for BART, as well as much of the remainder of the regional haze rule, applies to sources that may "reasonably be anticipated to cause or contribute to any impairment of visibility" in a mandatory Class I Federal area. This is a subtle but important distinction in terms of the applicability of the BART rule.

b. As discussed in the preceding response, the definition of "adverse impact on visibility" is relevant to 40 CFR 51.307 and not to the regional haze BART determination process (i.e., 40 CFR 51.308(e)). As such, the "time of visitor use" portion of said definition is not applicable to the BART determination. While "time of visitor use" is also included in the 40 CFR 51.301 definition of "significant impairment", the exemption from pollution controls provided by 40 CFR 51.303 requires approval from the Administrator and the Federal Land Manager. This exemption is not relevant to the GVEA BART analysis.

c. The BART rule does not exempt an affected source from the BART determination process based on available visibility monitoring; nor does available visibility monitoring account for the full geographic expanse of the Class I area modeling domain. In the technical review, the contractor, Enviroplan acknowledges the cited Department report and the quoted comment from that report. ,. Section 7.3 of the Findings Report provides a synopsis of both the VMP and the results, and it acknowledges the VMP findings. However, as indicated in Section 7.3, no known determination has been made by the regulatory authorities concluding that the VMP demonstrated no visibility impacts at DNPP, as caused by GVEA. While the VMP results suggest limited episodes of visible plume transport to DNPP directly attributable to GVEA, such results do not rule-out GVEA as a source reasonably anticipated to cause or contribute to any impairment of visibility. For example, as indicated in Section 7.3 of the April 27 Findings Report, IMPROVE data shows the year-round presence of sulfate and nitrate aerosols. This suggests that local combustion sources, e.g., Healy 1, are contributing to the airborne concentrations of such contaminants, and not just sources associated with international transport and wildfire events.

d. The Department and its contractor generally agrees with the premise that, if the Healy plant were impacting the Park visitor's center IMPROVE monitoring *station, a related improvement in the measured visibility parameters might be manifested at the time when new pollution controls were installed at Healy 1. However, no information on the general frequency or magnitude of station impacts attributable to Healy 1 is provided. Given that the Healy power plant is located in a valley with a northwest-southeast orientation the Department's technical review indicates that a relatively high percentage of the annual hours would reflect plume height flow vectors in this same alignment. This would suggest limited Healy 1 impacts at the IMPROVE monitor; therefore, the 1998 - 2007 trend data may not necessarily reflect implementation of controls at Healy 1. It is emphasized that low frequencies of Healy 1 impacts at the IMPROVE monitor does not mean no instances of plume transport towards DNPP; nor does it mean Healy 1 does not cause or contribute to any impairment of visibility.*

e. *Section 7.3 of the Findings Report acknowledges the contribution of international transport of aerosols into DNPP (Arctic Haze), as well as wildfire and in-park vehicle traffic. It is understood that these phenomena are potentially contributors to regional haze at DNPP; however, as indicated in the preceding paragraphs, this does not negate the BART rule and BART determination process for Healy 1.*

f. *The core requirements for a state regional haze SIP are provided at 40 CFR 51. 308(d). These requirements include reasonable progress goals and a long term strategy to attain natural conditions by the year 2064. The Department agrees that these elements of the SIP are collective, i.e., do not account for the actions of any particular source but consider all affected sources and their potential emissions reductions. However, 40 CFR 51.308(e) requires that the SIP contain emission limitations that reflect BART (and schedules for compliance) for each BART eligible source. While the results of the BART-related emission limits will be reflected in the long term strategy to ensure natural visibility compliance by 2064, the regional haze rule does not provide for a final determination on BART for an affected source pending the completion of the long term strategy.*

g. *As specified throughout this response document, the determination of SCR as preliminary BART has considered all information provided during the review. However, the consideration for the remaining useful lifetime of Healy 1 will affect the cost analysis and possibly the preliminary determination. The revised costing summary is presented at the end of this document; and related changes to the proposed BART determination for Healy 1 are contained in the BART/GVEA Determination Final Report*

11. Comment (page 10 of the letter, ***SO_2***): The commenter indicates their agreement that the existing dry sorbent SO_2 control system should be considered as BART; and that increased sorbent injection would add extra procedures and costs without a perceptible benefit to visibility. Likewise, the commenter opines the installation of a new lime spray dryer would result in even higher costs and related environmental impacts.

Response from the Department*: The GVEA cost analyses for the various SO_2 control options, including a new lime spray dryer, have been revised to account for an 8 year remaining useful lifetime for Healy 1. Further, a comment submitted by the*

Sierra Club has resulted in a revision to GVEA's cost analysis for increased sorbent injection at the existing FGD system as an SO_2 control option (see Sierra Club comment response 2). This cost analysis revision also considers related clarifying information provided by GVEA on August 27, 2009. The cost revision summary is presented at the end of this document, and any changes to the proposed SO_2 BART for Healy 1 are discussed in the Final BART/GVEA determination Report

12. Comment (page 10 of the letter, ***PM_{10}***): The commenter indicates their agreement that the existing fabric filter represents BART for this source; but does not believe the corresponding BART permit emission limit should be imposed.

    ***Response from the Department**: GVEA indicated in both a November 11, 2008 response to an information request, and their revised January 2, 2009 report, that the Healy 1 baghouse "is either achieving, or is capable of achieving, the 0.015 lb/MMBtu emission value" presented as BART for this control system. Review of proposed particulate emission limits summarized by the NPS for other BART EGUs using a baghouse[11] suggests the proposed emission limit for Healy 1 to be within the range of proposed and/or issued particulate BART limits for a fabric filter. This notwithstanding, the Findings Report erroneously expressed the PM emission limit as a 30-day rolling average instead of reflecting compliance based on source testing. The Final BART/GVEA determination Report is therefore revised to reflect a proposed preliminary BART particulate limit of 0.015 lb/MMBtu based on compliance source testing.*

13. Comment (page 10 of the letter, ***Conclusion***): The commenter requests the existing configurations for Auxiliary Boiler 1 and Healy Unit 1 be considered as BART, with no further controls and changes to in emission limits for each unit.

    ***Response from the Department**: The commenter's request is acknowledged. The Department agrees with the request for Auxiliary Boiler 1. All information and comments affecting the proposed preliminary BART determination for Healy 1, as contained in the April 27 2009 Findings Report, are documented herein. As discussed above, this includes a revision to the GVEA cost analyses for the NO_x and SO_2 control options in order to account for an 8-year remaining useful lifetime for Healy 1. Related information is summarized at the end of this document.*

[11] *NPS BART Evaluation, http://www.wrapair.org/forums/ssjf/bart.html .*

Comments received by the Department on June 15, 2009 from Sanjay Narayan on behalf of the Sierra Club, Denali Citizens Council, National Parks Council, Northern Alaska Environmental Center and Cook Inletkeeper

The commenter has provided comments in four itemized sections of their letter. The comments and Department responses are presented below consistent with these sections.

A. The Department Should Require Stricter Sulfur Dioxide Controls

1. Comment (3rd paragraph, page 2 of the letter): The commenter indicates the Department has rejected more stringent SO_2 controls on the basis of "brown-cloud" concerns. Based on their review of Section 3.2 of the Findings Report, the commenter suggests that the chemical reaction of NO to NO_2 associated with sorbent injection will occur relatively close to the source; will not represent new emissions; and will not make any difference in visible impacts at DNPP since chemical conversion will occur closer to the source versus during normal atmospheric transport and chemical conversation. The commenter also opines that, due to the lack of modeling by GVEA of this process, it is reasonable to expect that such transformation may accelerate particle deposition and visibility benefit to DNPP.

   ***Response from the Department**: As indicated in Section 3.2 of the April 2009 Findings Report, the potential does exist for the FGD reagent (sodium bicarbonate) to cause the oxidation of exhaust gas NO to NO_2. Section 3.2 of the April 27 Findings Report further indicates that a brief literature review was conducted on the potential for the formation of a brown-plume from this chemical reaction due to reagent usage. For instance, in a recent paper[12] prepared by Solvay Chemicals (i.e., vendor of dry sorbent (sodium bicarbonate) injection systems), it was shown that incremental increases in SO_2 control through increased sodium bicarbonate injection resulted in concurrent incremental increases in NO_2 formation (i.e., about 5 ppm NO_2 at 40% SO_2 control, up to about 25 ppm at 60% SO_2 control). A separate paper suggested a brown-plume to be visible at NO_2 concentrations of about 30 ppm; while a different paper suggested 90 ppm. The EPA[13] also acknowledges the potential for a brown-plume for this control system and sorbent type.*

   Clearly, increasing the plume concentration of NO_2 will result in an increased potential for the appearance of a brown-plume; however, this is not only dependent upon the NO_2 concentration in the plume, but it is also dependent upon meteorological conditions, particularly stable atmospheric conditions which limit plume dispersion and dilution. Given the proximity of the GVEA plant to DNPP (about 8km), The Department does not agree with the commenter that no difference in visible impacts will occur at DNPP due to the sorbent-based chemical conversion. Should a brown-plume occur, and possibly with increased frequency due to increased injection rates, the source proximity to the Park could increase the chances of observing a brown plume impacting DNPP due to insufficient time for plume dilution over a relatively short-travel distance. Such stable atmospheric conditions could also

[12]Yougen Kong and Jim Vysoky, "Comparison of Sodium Bicarbonate and Trona for SO_2 Mitigation at A Coal-Fired Power Plant", Solvay Chemicals Inc., presented at ELECTRIC POWER 2009, Rosemont, Illinois, May 12-14, 2009.
[13]U.S. EPA. "Multipollutant Emission Control Technology Options for Coal-Fired Power Plants, EPA-600/R-05/034, March 2005.

maintain a visible plume for relatively long time periods and distances, possibly resulting in the visible (brown) plume traveling well into DNPP.

The Department agrees that the above described phenomenon is qualitative only and GVEA did not conduct modeling to specifically evaluate potential brown-plume visible impacts at DNPP. The Department is not aware of any dispersion model capable of making such a demonstration. This notwithstanding, the goal of the regional haze program and BART rule is visibility improvement. The potential for such a visible plume occurrence as discussed above cannot be discounted, even if in a qualitative sense.

This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

2. Comment (5^{th} paragraph, page 2 of the letter): The commenter indicates the Department has rejected more stringent SO_2 controls on the basis of cost. The commenter indicates "The Department's economic analysis, however, fails to support that conclusion." To support this claim, the commenter indicates the following:

   - There are inconsistencies in the GVEA economic analysis between the baseline control efficiency and the increases in control efficiency for alternative control options. For instance, an efficiency increase of 40 percent for the existing FGD system (baseline control efficiency of 40-50 percent) implies an 80 to 90 percent control for the cost analysis, rather than the 70 percent control reported by GVEA.
   - GVEA significantly overestimated the amount of sodium bicarbonate reagent needed to achieve 70% control, citing a 1995 U.S. Department of Energy report at the Arapahoe Station (*Integrated Dry NO_x/SO_2 Emissions Control System Sodium-Based Dry Sorbent Injection Test Report)* that presents the sodium bicarbonate-to-SO_2 titration ratio as a function of SO_2 control rate.
   - Based on the above, GVEA's assertion that an entire new reagent injection system, at a capital cost of $2,000,000, would be needed to achieve 70% SO_2 control appears to be excessive.
   - The commenter opines that efficient reagent utilization at Healy appears to be poor. While the commenter acknowledges that temperature, mixing time, and particle size are key factors in achieving efficient control, they contend that the Department should require an independent assessment of the current dry sorbent injection system to determine the maximum SO_2 emission reduction that is achievable with optimized temperature, mixing, and reagent selection including particle size of the reagent.

   Response from the Department: *The commenter appears to have misinterpreted GVEA's estimates of the incremental increases in SO_2 control efficiency relative to the baseline control level. GVEA has expressed these incremental increases as being <u>relative</u> to the baseline and not <u>in addition to</u> the baseline. For example, assuming a baseline control efficiency of 50% for the existing sorbent injection system, an increase in control efficiency of 40% would result in an overall control efficiency of*

70% (i.e., 50% plus 40% of 50%), and not 90% (i.e., 50% plus 40%), as the commenter claims.

Enviroplan reviewed the cited 1995 U.S. Department of Energy report for the Arapahoe Station, which provides information on the stoichiometric ratio of sodium bicarbonate to flue gas sulfur needed for varying levels of flue gas SO_2 control. Based on this review, Enviroplan has determined that about a 50% increase in the sorbent injection rate will be needed to achieve 70% SO_2 control relative to a baseline of 50% control. However, in order to estimate the magnitude of the increase in the sorbent injection rate needed, the coal sulfur variability must also be accounted for, as described by Enviroplan below.

*"GVEA has reported that it currently injects 370 lb/hr of sorbent to achieve 50% SO_2 control for a coal sulfur content of about 0.17% by weight. This information was cited in their January 2009 report; and again reiterated in an August 27, 2009 submittal that responded to an August 17, 2009 Department request for related information. Usibelli coal property data presented by GVEA indicates a coal ash content of 13.65% and a coal heat content of 6,766 Btu/lb. Based on these properties and relevant data found in EPA's AP-42 emission factor document, the 0.17% sulfur content corresponds to an uncontrolled SO_2 emission rate of about 0.43 lb/MMBtu, which is significantly below the uncontrolled emission rate of 0.60 lb/MMBtu that forms the basis for GVEA's economic analysis. The baseline (50% control) sorbent injection rate must, therefore, be normalized to an uncontrolled SO_2 emission rate of 0.60 lb/MMBtu. This results in an adjusted baseline sorbent injection rate of (0.60/0.43)(370 lb/hr) = 512 lb/hr. To achieve a 70% SO_2 control, the sorbent injection rate must be increased to a level about 50% higher than the adjusted baseline injection rate, or 772 lb/hr of sorbent. (As a point of clarification, Enviroplan notes that GVEA's estimate of the sorbent injection rate needed to achieve 70% control was based on the high-end of the range in coal sulfur content, i.e., 40%. When combined with GVEA's estimated 40% increase in the stoichiometric ratio of sorbent to sulfur, this results in a GVEA computed injection rate of (0.40/0.17)(1.4)(370 lb/hr) = 1,219 lb/hr. However, Enviroplan does not believe this estimate to be valid, as it would not be possible for GVEA to meet the required SO_2 emission rate of 0.18 lb/MMBtu at 70% control using a coal with an annual average sulfur content of 0.40% (i.e., based on the above revised analysis, a 0.40% average sulfur content and 70% system control would equate to 0.3035 lb/MMBtu (0.43*0.40/0.17*0.30), rather than 0.18 lb/MMBtu))."*

"Therefore, the increase in sorbent injection rate needed to achieve 70% control relative to the current 50% control, based on a coal supply having an uncontrolled SO_2 emission rate of 0.60 lb/MMBtu, is: 772 lb/hr – 512 lb/hr = 260 lb/hr. For a reported sorbent cost of $335/ton, this results in an annual increase in sorbent costs of (260 lb/hr)(8,760 hrs/yr)($335/ton)/(2000 lb/ton) = $381,498/yr. The average and incremental cost effectiveness, based on controlling an additional 177 tons of SO_2, is $2,155/ton. This variable cost reflects only the cost of additional sorbent."

"In addition to the above, GVEA has indicated the existing Healy Unit 1 sorbent injection system has a maximum design capacity for sorbent injection of 600 lb/hr per

*feeder for two feeders (i.e., 1,200 lb/hr total maximum design capacity). Although it is possible to operate two feeders simultaneously, the system was not designed with the redundancy needed for continuous operation, without interruption, at this maximum design capacity. The design capacity does not account for regularly scheduled maintenance, unexpected system failures, and operating requirements. On this basis, Enviroplan agrees with GVEA's inclusion of the capital cost of a new redundant reagent injection system in its economic analysis, as such is warranted to ensure continuous compliance with the related SO_2 emission limit. Variable and fixed operating and maintenance costs, including administration, maintenance labor, and electricity costs, but excluding the first year reagent cost which was addressed in the preceding paragraphs, will also be incurred beyond those costs existing for the current system. GVEA estimated these costs as approximately $200,000/year in their March 2009 submittal, based on EPA cost information[14]. GVEA did not provide a detailed breakdown of their O&M cost and Enviroplan believes some of these costs are already built into the existing FGD system. Therefore, Enviroplan has revised the GVEA fixed O&M cost estimate to reduce it as a simple economy of scale, and only the GVEA estimate for additional electric usage (taken from Appendix A of the July 2008 GVEA BART report) is used for the variable O&M costs, as follows: (260/512)[($7,821/yr) + ($1.6/kw-yr*25000kw)] = $24,284/yr."*

On the basis of these considerations, the Department and its contractor has revised the cost analysis results for the existing sorbent injection system optimization option. Further, as explained elsewhere in this document, the cost analysis is also revised to reflect an 8-year remaining useful lifetime for Healy 1. The revised results and any changes to the proposed preliminary BART determination for control of SO_2 emissions are provided at the end of this document. Finally, regarding the suggestion that GVEA evaluate the existing FGD system for additional SO_2 reductions, as indicated by GVEA in their January 2009 report (Section 3.2.2.2), since installation of the control system in 1999, three different sorbents have been evaluated for purposes of improved SO_2 reductions. GVEA has indicated this evaluation has resulted in improved SO_2 emissions reduction based on the current use of sodium bicarbonate sorbent (versus calcium carbonate and trona).

B. The Department Should Require Stricter Oxides of Nitrogen (NOx) Emission Limitations

3. Comment (3rd paragraph, page 6 of the letter): The commenter indicates the Department was correct in requiring SCR as BART for NOx control (of Healy 1). However, the preliminary emission limit of 0.07 lb/MMBtu (30-day rolling average) is inconsistent with the combined performance of the current control system (LNB/OFA). The commenter asserts since SCR technology generally achieves 90 percent or better NOx emissions reduction, the combined emission limit should reflect 0.025 lb/MMBtu and not the approximate 70 percent reduction of the 0.07 lb/MMBtu preliminary emission limit.

[14]U.S. EPA. "Multipollutant Emission Control Technology Options for Coal-Fired Power Plants, EPA-600/R-05/034, March 2005.

***Response from the Department**: The determination of percent emissions reduction is referenced from a baseline. For Healy 1 with an existing LNB/OFA system baseline of 0.25 lb/MMBtu, the reduction to a vendor guaranteed emission limit of 0.07 lb/MMBtu results in a computed emissions reduction of 72 percent, as indicated by the commenter. As discussed earlier, the baseline has been revised based on comments provided by GVEA. The baseline, now at 0.28 lb/MMBtu, would result in a 75% emissions reduction versus the existing baseline. This notwithstanding, as addressed elsewhere in this document, the cost evaluation for SCR (and all other retrofit options) has been revised (see end of this document). The preliminary proposed BART for NOx, as SCR, is no longer deemed feasible.*

This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

C. <u>The Plant Contributes to Air Pollution in Excess of the National Ambient Air Quality Standards for Fine Particulates</u>

4. Comment (3rd and 4th paragraphs, page 7 of the letter): The commenter indicates that component PM emissions from Healy 1 include $PM_{2.5}$. The commenter additionally indicates that "the record includes no air quality modeling based upon local monitoring." The commenter further references an ambient $PM_{2.5}$ monitor located in the Fairbanks North Star Borough, and notes this to be within a $PM_{2.5}$ nonattainment area. The commenter concludes Healy 1 $PM_{2.5}$ emissions will add to the monitored pollution levels at this site, contributing air pollution in excess of the NAAQS. The commenter concludes by suggesting the proposed preliminary BART emission limits and control equipment within the Title V permit will result in a violation of the NAAQS and that the BART determination should address and eliminate the violation.

***Response from the Department**: The Department agrees that the component PM emissions from Healy 1 include $PM_{2.5}$. However, the Department does not understand the commenter's indication pertaining to the lack of air modeling based on local monitoring. The commenter appears to be concluding that Healy 1 is impacting the Fairbanks ambient monitor and is contributing to the nonattainment conditions of the area. This claim is unsubstantiated and, more importantly, unrelated to the regional haze program and BART rule.*

Therefore, no changes are made to the April 27 Findings Report due to this comment.

D. <u>Modeling of Impacts</u>

5. Comment (5th paragraph, page 7 of the letter which carries onto page 8): The commenter indicates the WRAP – RMC website spreadsheet of visibility monitoring parameters for the Healy Power Plant (i.e., ak_emi_01172007.xls) omitted HCCP from the visibility SIP inventory and the inventory should be corrected to include such.

***Response from the Department**: As indicated in Section 1.1 of the Findings Report, 40 CFR 51, Appendix Y, Section II defines a BART-eligible source as one that was in* *existence on August 7, 1977 and began operation after August 7, 1962. The HCCP project was approved for installation in 1994 and began operation during 1998. Therefore, HCCP does not qualify as a BART-eligible source.*

There is no change to the Healy Power Plant BART inventory or Findings Report due to this comment.

6. Comment (pages 8 and 9): The commenter indicates the WRAP – RMC website spreadsheet of visibility monitoring parameters for the Healy Power Plant (i.e., ak_emi_01172007.xls) contains erroneous SO_2 emission rates. The commenter also indicates the BART modeling parameters provided by the Department, also found on the WRAP – RMC website (i.e., Alaska_bart_stack_parameters_09_12_06.xls), to replicate the error shown in the WRAP spreadsheet.

   ***Response from the Department**: The Department agrees with the commenter that the WRAP spreadsheet listed SO_2 emission rate of 0.0163 g/s (0.1291 lb/hr and 3.0973 lb/day equivalents) is erroneous. The erroneous emission rate was acknowledged by the Department during Enviroplan's findings review. As such, Section 7.1 of the final Findings Report does indicate that the Healy 1 peak 24-hour SO_2 emission rate utilized in the visibility impact modeling is 182.2 lb/hour (4372.8 lb/day), reflective of a CEM-based peak 24-hour emission rate of 0.54 lb/MMBtu. This correct SO_2 emission rate was used in the GVEA visibility modeling analysis, as indicated in Section 7.1 of the Findings Report (and reflected in the dispersion modeling files); therefore, no changes are required to the report due to this comment.*

Comments received by the Department on June 15, 2009 from Don Shepard of the National Park Service (NPS)

The NPS comments were comprised of a comments document, and five accompanying appendices (Appendix A- E).

1. Comment (page 1 of comments document, **BART Analysis for NOx, STEPS 1-3**): The commenter indicates GVEA evaluated a reasonable spectrum of NO_x control options. However, the commenter indicates that EPA's Clean Air Markets (CAM) data and vendor guarantees, such as that indicated by Minnesota Power in their Taconite Harbor BART analysis, show that SCR can typically meet 0.05 lb/MMBtu (or lower) on an annual average basis. The commenter indicates GVEA has not provided documentation or justification for the 0.07 lb/MMBtu in their analysis. The commenter suggests, based on their review of CAM operating data for the 2006 ozone season for a similar boiler type (i.e., wall-fired dry-bottom), a NO_x limit of 0.06 lb/MMBtu for a 30-day rolling average; 0.07 lb/MMBtu for a 24-hour limit and visibility modeling; and 0.05 lb/MMBtu (or lower) for an annual average limit and cost estimation purposes.

   ***Response from the Department**: GVEA indicated in both the July 2008 and January 2009 BART reports that the SCR information provided by their consultant, CH2M Hill, was based on the compilation of similar proprietary control project information. During a February 27, 2009 teleconference, CH2M Hill reiterated the emission limit was based on their proprietary compiled vendor data.*

   The above notwithstanding, The Department recognizes the actual operating data provided by the NPS (Appendix B to their comments, as taken from the EPA's CAM database). The data indicate 30-day rolling NO_x emission rates of 0.06 lb/MMBtu (and lower) on an actual operating basis. Enviroplan's technical review raised several concerns associated with the use of this information for setting a BART emission limit for Healy 1. First, while the NPS summary statistics are recognized, not all listed EGUs are shown to achieve this emission limit at all times. Second, the data sample (2006 ozone season, i.e., May - September) is limited to only one 5-month period, and it is unclear how the actual 30-day rates might vary over a full year or over the full time-span since each retrofit system was brought online. Third, the regulatory basis reflected in the NPS example data are not BART; instead, the data reflects NOx SIP and ozone/$PM_{2.5}$ NAAQS compliance programs primarily (if not exclusively) for the eastern U.S. In that regard, the following additional concerns are noted:

   - *Enviroplan's technical review does not come to the same conclusion as the NPS that the eastern U.S. NO_x SIP program requirements to be equivalent to BART (regional haze) program requirements, even though the same control equipment can be used in response to the requirements of each program. The actual ozone-season emission rates summarized by the NPS are acknowledged; however, the level of control and period of system usage for compliance with the NOx SIP for ozone/$PM_{2.5}$ NAAQS compliance versus visibility improvement under the regional haze program are different. For instance, during the ozone season an affected source can opt to over-control their NO_x emissions for purposes of establishing* *saleable NO_x credits under a related cap-and-trade program. During the "off-season" there is ample time for control system maintenance. There is no distinction within the CAM-based data for such a scenario, and reliance on actual emissions data as a basis for BART would not be appropriate.*

- *In relation to the above, it is unclear whether a stoichiometric NH_3/NOx ratio of 1:1 is being maintained to achieve the CAM-based 30-day emission rates or if a ratio greater than 1:1 ratio is being used. While unreacted ammonia emissions (slip) are typically maintained in a range of 2-5 ppm for a 1:1 ratio, a system operated under a high NOx reduction scenario could have a substantially higher atmospheric ammonia emission rate causing offsetting deleterious visibility impacts. It is unclear whether the CAM-based ozone-season emissions data reflects this high NOx reduction/ammonia slip scenario.*
- *The CAM data show that actual 30-day emission rates are generally lower than the 0.07 lb/MMBtu rate proposed for Healy 1; however, actual operating data are different from a vendor guaranteed emission rate which takes into account site-specific operating conditions and maintenance requirements. The guaranteed NOx limit provided by each retrofit system vendor for the CAM-based units is unknown.*
- *Irrespective of the CAM-based data, NPS BART summary data for western EGUs (see Response 6.g to GVEA's comments in this document) indicates only 3 other BART eligible units (excluding Healy 1) have proposed SCR for NOx control (and two additional units as reasonable progress); the minimum capacity of those units is 375 MW (as compared to 25 MW Healy 1); each with a proposed emission rate of 0.07 lb/MMBtu. The BART rule provides for consideration of other similar determinations.*
- *Use of a 0.05 lb/MMBtu NOx limit for Healy 1 for an annual emission rate and cost effectiveness determination, as suggested by the NPS, would not account for the fact that the CAM-based data reflects only a 5-month period of operation, i.e., this data does not reflect full year use of an SCR control system at the NPS recommended emission rate. The department's contractor's review does not support that the continuous operation of a SCR control system at this low emission rate can be compared to limited ozone-season SCR use reflected in the CAM-based data. The recently adopted regional haze plan developed by the Oregon Department of Environmental Quality (DEQ) provides further basis for this assertion, as discussed below.*

  The Oregon regional haze plan was adopted on June 19, 2009. The Oregon SIP includes pollution controls for the Portland General Electric Company (PGE) Boardman plant's 617 MW coal-fired boiler, which is a BART-eligible EGU. The DEQ concluded that SCR would be installed as additional NOx control for reasonable progress under the plan (rather than initial BART control). In deciding the appropriate corresponding NOx emission limit, DEQ noted "In terms of the reductions achievable by SCR, DEQ conducted a more extensive evaluation of the SCR control effectiveness. There are 190 coal-fired electric generating units with SCR controls in the U.S. In 2008, 17 of the 190 units had an annual average emission rate less than 0.07 lb/MMBtu and only three of the

17 were dry bottom wall-fired units. The lowest emission rate for the dry bottom wall fired units was 0.052 lb/MMBtu as an annual average. When evaluated on a 30-day rolling average, the 95% confidence level was 0.068 lb/MMBtu. Based on this data, DEQ believes that the control effectiveness (e.g., 0.07 lb/MMBtu) used in the BART analysis represents the best controlled dry bottom wall-fired unit in the U.S."[15] This recent thorough investigation by the DEQ suggests the 0.07 lb/MMBtu NOx emission limit proposed for Healy 1 to be an appropriate continuous rate for the emission unit. In addition to the above, the DEQ also indicated[16] "Some power plants on the east coast using SCR have achieved NOx reductions as high as 90 percent and are required to meet stricter emission limits. However, these SCR systems were developed to help address seasonal ozone (smog) conditions. Seasonal operation provides substantial opportunity for off-season maintenance and catalyst cleaning, which means they can routinely optimize the SCR's ability to meet lower limits."

Like the Boardman plant, the BART retrofit control system selected for Healy 1 (in this case, SCR as proposed in the April 27 Findings Report) would require year-round operation. The SCR system would operate for long periods of time without catalyst cleaning or system maintenance. As further noted by the DEQ, and as reflected in actual operating data provided by the NPS from the CAM-based data, normal day-to-day emissions typically occur at levels well below the emission limit but do demonstrate variability in response to changes in daily activity (similar variability was demonstrated in 5-year CEM emissions data provided by GVEA during March 2009). Based on the above considerations and the other factors associated with the regional haze program requirements, the DEQ concluded a NOx limit of 0.07 lb/MMBtu to be sufficiently strict and not set unrealistically low such that the unit would not be able to continuously meet the limit in its day-to-day operations.

The Department determined the same concerns specified above to be applicable to Healy 1. The 30-day emission limit of 0.07 lb/MMBtu proposed for Healy 1 remains unchanged.

The NPS also suggested the BART determination for NOx include a 24-hour average (0.07 lb/MMBtu) and annual average (0.05 lb/MMBtu) emission limits. It is understood that visibility modeling and control option costing are component BART analyses, respectively utilizing peak 24-hour and annual average unit emission rates. However, as indicated in Section 9.1 of the April 27 2009 Findings Report, 40 CFR 51, Appendix Y, Section V specifies that an EGU emission limit reflect a 30-day rolling average based on the "boiler operating day" definition of 40 CFR 60, Subpart Da. Therefore, the proposed NOx BART emission limit for Healy 1 is reflective of the 30-day rolling average consistent with the BART Guideline.

2. Comment (page 1 of comments document, **BART Analysis for NOx, STEP 4**): The commenter indicates that GVEA has overestimated the cost of SCR. The commenter indicates the BART cost analysis should have utilized the OAQPS Control Cost

[15]Memorandum entitled "J-RegionalHaze_includes RTC.pdf", dated May 22, 2009, taken from http://www.deq.state.or.us/aq/haze/pge.htm.
[16] See http://www.deq.state.or.us/aq/haze/pgeQA.htm.

Manual as per the BART Guidelines. The commenter indicates that it is EPA's belief that the Control Cost Manual should be applied instead of the CUECost model, based on the commenter's citing of a November 7, 2007 statement made by EPA to the North Dakota Department of Health. As noted by the commenter, the EPA indicated that the Control Cost methodology should be used instead of the CUECost methodology "in order to maintain and improve consistency" in accordance with the BART guidelines. The commenter further believes the capital and annual costs to be overestimated since GVEA did not provide vendor estimates or bids. The commenter indicates GVEA's equivalent SCR capital cost of $351/kW to be high compared to the commenter's survey data for SCR (i.e., $50 - $267/kW).

***Response from the Department**: The Department acknowledges the commenter's indication on the BART Guideline's recommended use of the Control Cost Manual (40 CFR 51, Appendix Y, Section IV.D.4.a.5) for cost consistency purposes. However, the Guideline does not exclusively require use of this document, indicating that documentation should be provided for cost calculations that might differ from the Control Cost Manual. Since the EPA's CUECost tool has been developed for cost estimation of air pollution control systems installed on coal-fired utility emission units, the Department determined that CUECost to be suitable for the BART cost analysis. This aside, the Department agrees that GVEA's consultant, CH2M Hill, did not divulge the specific vendor(s) upon which the SCR costs (and emission limit) are based. Their costing information was deemed by the Department, pursuant to the request of GVEA, to be proprietary and confidential.*

The above notwithstanding, a SCR application consulting company was contracted by GVEA to conduct a site evaluation and develop a refined cost estimate for a retrofit SCR system for Healy 1. The evaluation occurred on May 27, 2009. The consultant, Fuel Tech, Inc., provided a project report on June 10, 2009 which was included with GVEA's June 15, 2009 comments. Fuel Tech estimated the site-specific capital cost for the SCR retrofit project at $13,300,000. Related costs for project management, engineering, equipment relocation, demolition, new induced draft fan and motor, duct stiffening, and other onsite modifications, and relevant O&M costs, were estimated by GVEA per Fuel Tech recommendations. The Guideline supports the use of site-specific design and other conditions that affect the cost of a particular BART analysis. GVEA has revised their SCR cost evaluation using the Fuel Tech study data as input to their CUECost cost analysis, as discussed in the GVEA comments section of this document. The revised cost analysis is presented at the end of this document.

With respect to the commenter's SCR cost survey data (Appendix C to their comments) two points of clarification are noted. First, Enviroplan utilized the NPS survey information in the BART determination for Healy 1, as discussed in Section 6.1 of the Findings Report. Second, one of the data sources used by the NPS for their cost survey is the recently finalized PGE Boardman Plant BART determination. It is noted that CUECost was the basis of the PGE and Oregon DEQ cost analysis for Boardman.

3. Comment (page 2 of comments document, **BART Analysis for NOx, STEP 4**): The commenter acknowledges that GVEA's cost analysis reflected a *remaining useful life*

of 15 years. However, the commenter notes this period to be less than the assumed 20 years for SCR in the Control Cost Manual. The commenter has qualified their acknowledgement of this period by indicating the 15-year period must become an enforceable permit condition of a final permit should the period be important in the final BART determination. The commenter also notes their estimate of SCR costs based on the Control Cost Manual.

***Response from the Department**: The 20 year value within the Control Cost Manual is only a default value that does not directly account for specific operating conditions in a particular locale. As indicated in Section 6.1 of the Findings Report, other control technology reviews conducted by the Department have reflected SCR lifetimes of 10 years due to the harsh operating environment within the state. As such, the use of a 15 year lifetime for a SCR system utilized in interior Alaska is appropriate, and possibly conservative, for this analysis.*

The above notwithstanding, the Department agrees that the remaining useful life of Healy 1 is a very important input parameter to the cost analysis, both in terms of the capital recovery factor and the determined cost effectiveness of each retrofit option. While the April 2009 Findings Report did reflect a 15-year remaining useful life for Healy 1, GVEA included in their June 15, 2009 comments a revised costing analysis reflective of an 8-year remaining useful life for Healy 1. As explained in the GVEA comments section of this document, this 8-year remaining useful life has been deemed as reasonable for Healy 1; and the revised cost analysis, inclusive of the site-specific cost estimate provided by Fuel Tech, has been accepted. The revised cost analysis is summarized at the end of this document;

In accordance with the cost analysis revision, the Final BART/GVEA Determination report has been revised.

4. Comment (page 3 of comments document, **BART Analysis for NOx, STEP 5**): The commenter indicates there should be a generally linear relationship between CALPUFF visibility modeling results and source emission rates. However, the commenter makes note of GVEA visibility modeling results and the expectation of better predicted visibility improvement than shown by GVEA (i.e., Tables 4-3 and 5-1 of the January 2009 GVEA report) for SCR versus LNB/OFA optimization. The commenter indicates that the GVEA data require further explanation.

***Response from the Department**: The CALPUFF model has a non-linear chemical transformation algorithm (MESOPUFF II) which is used in the visibility modeling. Generally, the algorithm converts source NOx emissions to nitric acid and organic nitrates which, in turn, combine with background ammonia (concentration specified as input to the model) to form ammonium nitrate. Source SO_2 emissions are likewise transformed to sulfates and then ammonium sulfate. However, as indicated in the CALPUFF model user's guide, "unlike sulfate, the ambient concentration of nitrate is limited by the availability of ammonia which is preferentially scavenged by sulfate." As such, due to the preferential chemical reaction between sulfates and ammonia, NOx source emission rate changes may not necessarily manifest a proportional change in visibility improvement as suggested by the commenter.*

Enviroplan has reviewed the CALPUFF modeling files provided by GVEA (created by CH2M Hill). Section 7 of the Findings Report summarized the results of the modeling file review and, unless noted, Enviroplan determined the GVEA modeling to be consistent with the WRAP-RMC protocol. Consequently, it is believed that the non-linear chemical transformation algorithm accounts for the disparate visibility impact results noted by the commenter.

The response noted above is for purposes of clarification and it does not change the conclusions of the April 2009 Findings Report.

5. Comment (page 3 of comments document, **BART Analysis for NOx, STEP 5**): The commenter makes reference to their survey of other BART proposals and associated cost effectiveness values expressed in terms of cost per deciview of improvement. The commenter notes that their survey suggests $10-$20 million/dv represents a "reasonable average cost-effectiveness for improving visibility at the most-impacted Class I area". As such, the commenter agrees that the April 2009 Findings Report cost effectiveness value ($1.6 million/dv of improvement for SCR on Healy 1) to be favorable in terms of SCR installation, but continues to suggest a NO_x limit of 0.06 lb/MMBtu for a 30-day rolling averaging period.

   ***Response from the Department**: With respect to the emission limit comment, see response to comment 1 above. With respect to the cost effectiveness comment, site-specific SCR cost estimates and revised cost effectiveness calculations have been provided by GVEA as part of their comments on the Findings Report (see GVEA comments section of this document).*

   The summary of the revised cost analysis is presented at the end of this document, and related revisions have been made to the April 2009 Findings Report.

6. Comment (page 3 of comments document, **BART Analysis for SO2, STEP 3**): The commenter indicates that GVEA should explain how their uncontrolled emission rate of 0.60 lb/MMBtu was calculated.

   ***Response from the Department**: A request was sent by the Department to GVEA on August 17, 2009 to clarify their uncontrolled SO_2 emission rate of 0.60 lb/MMBtu (Section 3.2.2.3 of their January 20099 report). In a response provided on August 27, 2009, GVEA indicated that the uncontrolled SO_2 emission rate is based on coal analysis data from the Usibelli Mine, taking into account actual variability of the coal quality. This response is provided for purposes of clarification.*

7. Comment (page 4 of comments document, **BART Analysis for SO2, STEPS 1-3**): The commenter indicates that the spectrum of SO_2 control options is reasonable; however, the commenter indicates GVEA underestimated the ability of the lime spray dryer (LSD) flue gas desulfurization system to reduce uncontrolled SO_2 emissions. The commenter notes a May 2005 PSD permit that established a 24-hour average emission rate of 0.065 for a LSD system (93% control), as compared to the GVEA emission rate of 0.15 lb/MMBtu (75% control relative to an uncontrolled baseline emission rate). Similarly, the commenter indicates the wet scrubber emission rate of

0.07 lb/MMBtu (88% control) to be understated, noting a July 2008 PSD permit with a 24-hour average emission rate of 0.06 lb/MMBtu. The commenter has indicated the LSD control option, combined with the existing fabric filter (FF, or LSD-FF), to be the optimum SO_2 control option versus a wet FGD system.

Response from the Department*: The Department provided the commenter with preliminary review of the draft BART determination for Healy 1 during January and February 2009; and the Department indicated to the commenter on February 12, 2009 the plan to focus the SO_2 retrofit evaluation on optimization of the existing sodium bicarbonate FGD SO_2 control system. This decision, based on a requisite timeline for completion of the State's regional haze SIP, has not been altered.*

The above notwithstanding the Department agrees that the wet FGD option is unfavorable when compared to the LSD-FF for the reasons noted by the commenter (and as indicated in the April 27 2009 Findings Report). For the LSD option, the Department contractor, Enviroplan has reviewed a number of sources of related information, including the EPA Clean Air Markets (CAM) based data (for SO_2 emissions) as referenced in response 1 above; EPA control technology documents, New Source Performance Standards (NSPS), Institute of Clean Air Companies, Department of Energy research documents, the NPS BART analysis summary data for other coal-fired electric generating units, and pollution control technology vendor websites. In general, the technical review agrees that these various information sources do indicate an upper-bound 90 to 95% control efficiency for LSD (versus uncontrolled). However, the information also provides lower bound estimates that include 80% (see footnote [17] for example).

The performance of the LSD system in terms of SO_2 control is a function of the fuel sulfur content. As indicated in their January 2009 submittal, GVEA has specified that the Usibelli Coal Mine is the source of the Healy 1 coal. The coal has a very low-end sulfur content at 0.17% by weight (0.23% for calendar year 2005, based on a comment by the Sierra Club), and the degree of SO_2 removal by an LSD system for such low sulfur coal is unclear. The commenter's indication of the SO_2 reductions achieved in the referenced PSD permits were based on coal with sulfur contents of 0.45% and 0.82%, respectively. In fact, as was recently noted by the Oregon DEQ during their regional haze SIP development process[18], the EPA established differing criteria in the NSPS for electric generating units (40 CFR 60, Subpart Da) to account for diminished control efficiencies under a lower sulfur condition (i.e., reduce SO_2 emissions by 90% if the emissions are greater than 0.60 lb/MMBtu, and by 70% if the emissions are less than 0.60 lb/MMBtu).

A review of the EPA Clean Air Markets (CAM) data for SO_2 emissions (operating year 2007) indicates, for those EGUs generally comparable to Healy 1 (i.e., wall-fired EGUs) and listed as using dry lime FGD, a range of emission rates from 0.07 lb/MMBtu (361 MW) to 0.17 lb/MMBtu (571 MW). Further, two wall-fired units with capacities between 25-100MW, using dry lime FGD, are shown to have SO_2 emission rates of 0.14 and 0.15 lb/MMBtu (90 MW and 91 MW, respectively). Additionally,

[17] EPA, "Air Control Technology Fact Sheet: Flue Gas Desulfurization (FGD) - Wet, Spray Dry, and Dry Scrubbers", dated July 15, 2003, taken from http://www.epa.gov/ttn/catc/products.html#aptecfacts .
[18] Memorandum entitled "J-RegionalHaze_includes RTC.pdf", dated May 22, 2009, taken from http://www.deq.state.or.us/aq/haze/pge.htm.

review of NPS survey data[19] [20] *indicates for those EGUs most comparable to Healy 1 (wall-fired EGUs using a lime spray dryer, irrespective of capacity) shows SO_2 emission rates in the range of 0.12 lb/MMBtu (PGE Boardman) to 0.15 lb/MMBtu (Colorado Springs, Martin Drake), and even higher for Great River Energy. This information generally illustrates the variable nature of the SO_2 emission rate associated with the LSD system.*

The above notwithstanding, assuming what is believed to be an unrealistic emission rate of 0.06 lb/MMBtu for Healy 1, would result in an average cost effectiveness of over $5,800/ton of pollutant removed based on the 8-year revised cost analysis. This cost is still almost 3 times the $2,000/ton presumptive limit cost metric established by EPA in the BART rule. Therefore, based on this lower-bound cost estimate and the uncertainty with respect to being able to achieve continuous compliance with 90% control efficiency (or 0.06 lb/MMBtu as suggested by the commenter) for the low sulfur Usibelli Mine coal, the Department concludes the LSD SO_2 emission limit, which is consistent with the emission rates summarized above and the presumptive EGU emission limit established by EPA in the BART Guideline, to be acceptable for the LSD control option for Healy 1.

8. Comment (page 5 of comments document, **BART Analysis for SO2, STEP 4**): The commenter indicates that the SO_2 cost analysis is flawed. The commenter notes that only an incremental cost analysis was reflected in the January 2009 report by GVEA; and the April 2009 Enviroplan Findings Report. The commenter recommends the SO_2 control analysis for LSD and wet FGD be considered replacement controls for the existing dry FGD system, as was reflected in the original July 2008 GVEA report. The commenter provided their own estimate of annual average cost for the LSD system, based on use of the EPA Control Cost Manual and 90% control for the LSD system.

Response from the Department*: With respect to a 90% control efficiency for the LSD system option, please see response 7 above. The Department does not agree with the commenter that only the incremental cost analysis is considered in the BART review. As indicated in the GVEA January 2009 report (Table 3-4) the cost analysis includes both an annual average and incremental cost estimate for each control option. The related cost effectiveness determinations are based on the existing controlled SO_2 baseline emission rate which is consistent with the BART Guideline. The April 27 Findings Report (Table 6-2 and Section 7.4) likewise reflects annual cost estimates for these options. While there is no change to the Findings Report due to this comment, the costing analysis for the LSD and wet FGD options are revised to reflect an 8-year remaining lifetime for Healy (see related discussion under GVEA comments in this document, and the revised cost analysis summary at the end of this document).*

9. Comment (page 5 of comments document, **BART Analysis for SO2, STEP 5**): The commenter indicates the GVEA visibility modeling analysis is flawed for several

[19] NPS BART Evaluation, http://www.wrapair.org/forums/ssjf/bart.html .
[20] Email forwarded by Don Shepherd, NPS, to various recipients, subject title "Latest Compilation of BART Determinations and Proposals Attached BART Evaluation", dated August 12, 2009.

reasons. First, the commenter indicates GVEA should have evaluated all DNPP receptors and not just the most impacted receptor when assessing the effects of a lower plume height on visibility changes at DNPP from LSD and wet FGD (versus the existing dry sorbent injection FGD system). Second, since the commenter believes GVEA to have understated the control efficiency of an LSD system (see comment/response 7 above), they indicate a resultant overestimate of remaining emissions and related impacts have occurred. Third, GVEA did not evaluate the Healy 1 stack to determine the GEP stack height and potential for building downwash. The commenter believes the FF-LSD FGD option may represent SO_2 BART for Healy 1.

Response from the Department*: With respect to the LSD and wet FGD options, see response 7 above. The Department acknowledges the modeling comment but notes the following. First, GVEA used the full range of DNPP receptors in the CALPUFF visibility modeling analysis, as taken from http://www2.nature.nps.gov/air/maps/Receptors/index.cfm (see Section 7.1 of the Findings Report). Ranked delta-deciview visibility impacts were determined by GVEA using CALPOST for the pre- and post-control scenarios. While the BART Guideline requires a comparison of the 98th percent days for the pre- and post-control scenarios, GVEA conducted the required comparative assessment using maximum delta-deciview values (pre- versus post-control) since only one year of meteorological data was used in the analysis. This is consistent with Department BART modeling requirements. The comparative analysis results were presented in Section 7.4 of the Findings Report. Although the comment on the full range of receptors is acknowledged, a receptor-by-receptor analysis is not required in the BART Guideline.*

With respect to the potential for aerodynamic building downwash, a GEP stack height analysis was not included in the GVEA visibility modeling analysis. This is consistent with the WRAP modeling protocol which was followed by GVEA to conduct their visibility impact analysis.

10. Comment (page 6 of comments document, **BART Analysis for PM_{10}, STEP 1**): The commenter indicates agreement that the existing reverse-gas fabric filter (baghouse) at GVEA to be BART for filterable PM_{10}; however, the commenter specifies that GVEA must also evaluate controlling condensable PM_{10}. The commenter notes condensable PM_{10} typically equals or exceeds filterable PM_{10} emissions.

Response from the Department*: The Department provided the commenter with preliminary review of the draft BART determination for Healy 1 during January and February 2009; and the Department indicated to the commenter on February 12, 2009 the plan to focus the retrofit evaluation on the existing baghouse control system. This decision, based on a requisite timeline for completion of the State's regional haze SIP, has not been altered.*

The above notwithstanding, the existing baghouse is used for control of filterable particulate matter. The baghouse also provides complimentary benefit to the SO_2 control system (sorbent injection into the ductwork prior to the baghouse resulting in dry sulfate particles captured at the baghouse). At this time, control efficiencies for *condensable PM are not well understood (e.g., see Federal Register Notice 74 FR 36427, July 23, 2009); and are not required to be accounted for in NSR permitting processes. EPA is aware of the positive bias (overstatement) that exists when determining condensable PM emissions with Method 202, and is presently developing a revision to the test method to accurately account for condensable particulate formation. Regardless, it is anticipated that the degree of control of condensable PM will be similar between a cold-side ESP and a baghouse. In addition, the baghouse is capable of a higher emission reduction for filterable PM. Hence, at this time, the Department sees no benefit of adding an additional PM_{10} control device in place of, or in addition to, the existing baghouse for controlling condensable PM.*

This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

11. Comment (page 6 of comments document, **BART Analysis for PM_{10}, BART Modeling Analysis**): The commenter indicates their disagreement with GVEA's specification in their January 2009 report (page 4-5) that modeled particulate emissions were not speciated. The commenter notes a statement from the WRAP protocol (page 1-2)[21] that indicates PM_{10} emissions should be broken into specified species. The commenter also inquires on whether building downwash from Healy 1 was applied in the CALPUFF modeling; and they request the UTM coordinates for the Healy 1 stack. Finally, the commenter inquires whether the receptors were obtained from the NSP web site)[22] .

    ***Response from the Department**: The comment incorrectly implies that GVEA did not follow the WRAP protocol. GVEA actually used the same approach as WRAP, as allowed under 18 AAC 50.260(h)(3)(A).*

    While the commenter correctly noted WRAP's statement that PM_{10} emissions "should be" speciated, they overlooked WRAP's following statement: "However, in reality most States provided PM emission estimates for their potential BART eligible sources as total PM_{10} without speciation. In this case [WRAP] will model the PM_{10} as $PM_{2.5}$ and summarize the PM contribution to light extinction for the highest visibility impairment days and it will be up to the States to justify performing the BART exemption screening analysis without speciating the PM emissions (see Section 1.2 for extinction characteristics of the different components of PM)."

    Alaska was one of many states that provided PM emissions as total PM_{10} emissions, since this is the emissions format that is readily available from the permit files. WRAP, and later GVEA, therefore modeled the PM emissions as stated in the protocol – i.e., without speciation. This" fall-back" approach was clearly noted in the protocol, and was not challenged by the NPS during the protocol development phase (which included teleconferences with the NPS); the subsequent modeling teleconferences with industry, EPA and the federal land managers; or the eventual adoption of the WRAP protocol in the Department's BART regulations. The

[21]WRAP. *Draft Final Modeling Protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States.* Air Quality Modeling Forum. Regional Modeling Center. August 15, 2006.
[22]http://www.nature.nps.gov/air/maps/receptors/index.cfm .

Department therefore considers the NPS objection to this established modeling approach as delinquent, especially since the Department is already notably behind the federally-established schedule for developing its Visibility SIP.

With respect to the comments on building downwash and the source of the receptors used in the modeling analysis, see response 9 above. These issues were discussed in Section 7.1 of the Findings Report. With respect to the UTM coordinates of the Healy 1 stack, GVEA used Lambert Conformal Conic (LCC) coordinates in their CALPUFF modeling consistent with the WRAP modeling (stack coordinates of 102.026 (LCC X (km)) and 545.101 (LCC Y (km))). This translates into UTM coordinates of 403.2984 km (easting) and 7081.5927 km (northing).

This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

12. Comment (page 7 of comments document, **BART Analysis for PM_{10}, Just Noticeable Differences in Atmospheric Haze**): The commenter disagrees with the GVEA assessment in their January 2009 report on what constitutes a perceptible change by the human eye of delta-deciview. GVEA indicates in their report that a deciview change of 1.5 to 2.0 dV to be perceptible; while the commenter notes competing studies as the basis for much lower perceptible changes. The commenter notes the use by EPA/RPO of 0.5 deciview and 1.0 deciview as the basis for determining whether a BART-eligible source is "reasonably anticipated to cause or contribute to visibility impairment"; however, the commenter specifies their belief that any improvement in visibility, no matter how small, should be considered when determining BART for an affected source.

    Response from the Department*: The Findings Report presented the visibility improvement modeling results associated with the baseline and each retrofit option evaluated for Healy. The related results summaries were not limited to visibility improvements exceeding any minimum threshold. The Department has adopted the BART Guidance threshold of 0.5 deciviews (18 AAC 50.260(q)(4)) as the basis for determining whether a source is "reasonably anticipated to cause or contribute to visibility impairment".*

    This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

13. Comment (page 7 of comments document, **BART Analysis for PM_{10}, Economic Impacts – Rate Payer Analysis**): The commenter cites specific phrases from citations within the BART Guideline that were referenced in the Findings Report. Most specifically, the commenter references 40 CFR 51, Appendix Y, Section IV.E.3 (i.e., *In selecting a "best" alternative, should I consider the affordability of controls?*); and highlights phrases within the citation that focus on the impact of a proposed control option on a plant, including affordability, profitability and competitiveness. The commenter believes GVEA did not make a showing that the proposed control options would jeopardize its ability to operate; and the commenter indicates that GVEA is not in a competitive market. Further, the commenter does not believe potential control costs should consider the localized impact on GVEA

customers since DNPP is a national park; and, given the source's contribution to visibility impairment at DNPP, the commenter indicates there is no allowance in the rule for consideration upon rate payers when assessing the five factors used to determine BART.

***Response from the Department**: The Department does not agree with the commenter's assertion that the BART Guideline does not provide for consideration of the impact on GVEA rate payers. As indicated in the Findings Report, and as acknowledged by the commenter, the cited BART Guideline section provides for the consideration where, even if deemed cost effective, installation of controls would affect the viability of continued plant operations.*

GVEA is a not-for-profit locally owned cooperative providing electric service to Interior Alaska. The Healy power station is part of the GVEA cooperative. GVEA serves a relatively small rural community that is not connected to a nationwide or outside electric grid; or connected to other utilities through a regional transmission organization for ample, readily dispatched electricity. Related electricity rates increased to pay for any add-on emissions controls would be directly borne by the relatively small rate payer community. Additionally, the stationary source is located in a remote area and not easily accessible year round for supply of fuel and ancillary operating/maintenance supplies. The Department therefore believes these conditions are unique to GVEA and are considered as "unusual circumstances" pursuant to the cited section of the BART Guideline.

There is no change to consideration of rate payer costs in the GVEA BART determination process due to this comment; however, as indicated in response 6 to the GVEA comments, the rate payer cost information is revised. The revision accounts for the consideration of the useful life of Healy 1, as discussed in the GVEA comments section for Healy 1.

14. Comment (page 9 of comments document, **Mercury Emissions**): The commenter notes the installation of SCR would likely promote oxidation of elemental mercury making it more readily removable using a downstream FGD system. The commenter requests consideration of this added environmental benefit to SCR plus FGD.

***Response from the Department**: Mercury is not a pollutant of concern under the BART Guidelines. Therefore, the Department cannot consider the potential benefits of controlling mercury as part of the BART control technology analysis process. However, the Department does acknowledge that during combustion, mercury is volatilized and converted to elemental mercury. As the flue gas is cooled, elemental mercury is converted to mercury compounds and ionic mercury (process known as mercury speciation). However, the oxidation reactions are kinetically limited. Mercury enters the flue gas control system as a mixture of elemental mercury, mercury compounds and ionic mercury. Mercury compounds and ionic mercury can be captured via existing baghouse and FGD control system. Based on studies conducted by EPA[23], it was shown that there will not be a significant increase in*

[23] http://www.epa.gov/ttnatw01/utility/hgwhitepaperfinal.pdf

mercury capture between a FGD only control system and a FGD + SCR control system.
This response is provided for a purpose of clarification and it does not change the conclusions of the April 2009 Findings Report.

Preliminary BART Determination Revisions Proposed by the Department

In response to GVEA comments, the Department has agreed that an 8-year remaining useful lifetime for Healy 1 is appropriate for use in the BART cost analyses. The final determination report is revised for the remaining SO_2 and NO_x control options to reflect an 8-year remaining useful lifetime for Healy 1. Several points are noted with respect to the revisions:

- Except for the site-specific SCR evaluation by Fuel Tech which reflects 2009 dollars, the revised analysis reflects 2007 dollars from the GVEA CUECost analysis (July 2008 report, January 2009 report revision, and March 2009 submittal).
- GVEA (CH2M Hill) escalated the 2009 dollar amounts for the SCR system to 2016 dollar amounts (using a 3% escalation factor); however, Enviroplan used only current (non-escalated) cost information. Although the SCR system components would be purchased in and around the 2016 time-frame, the costs were not adjusted to that calendar year since cost comparison metrics would also have to be adjusted to 2016; therefore, both the system and metric costs were retained in current unadjusted dollars.
- Only capital costs are affected by the reduction from a 15-year to an 8-year useful lifetime amortization period. A linear adjustment has been made to the capital cost for each option using the ratio of 8-year to 15-year capital recovery factors (CRFs). Previously provided GVEA control option O&M costs are unchanged unless otherwise noted.
- The 15-year cost analysis results for each option are shown for comparative purposes, but only the 8-year analysis results are reflected in the revised Findings Report.
- The revised 30-day average NO_x baseline emission rate of 0.28 lb/MMBtu is used in the revised cost analysis, per the comment made by GVEA. The Findings Report is revised to reflect the cost analysis results associated with this revised baseline emission rate.

Summary of Enviroplan Revised SO_2 Cost-Effectiveness Calculations Based on an 8-Year Remaining Lifetime for Healy Unit 1

Remaining Useful Life	Cost Item	Optimization of Dry Sorbent Injection System	Semi-Dry FGD (Lime Spray Dryer)	Wet Limestone FGD
15 Years[5]	Total Installed Capital Cost	$2,000,000 ($80/kw)	$8,357,143 ($334/kw)	$15,042,857 ($602/kw)
	Capital Recovery	$233,660[1]	$976,361[1]	$1,757,450[1]
	Fixed and Variable O&M Costs	$405,782[2]	$631,511	$901,654
	Total Annualized Cost	$639,442	$1,607,872	$2,659,104
	Tons SO_2 Removed	179	223	343
	Average Cost Effectiveness ($/ton)	$3,578[3]	$7,198[3]	$7,763[3]
	Incremental Cost Effectiveness ($/ton)	$3,578[3]	$21,677	$8,824
8 Years	Total Installed Capital Cost	$2,000,000 ($80/kw)	$8,357,143 ($334/kw)	$15,042,857 ($602/kw)
	Capital Recovery	$348,020[4]	$1,454,227[4]	$2,617,608[4]
	Fixed and Variable O&M Costs	$405,782[2]	$631,511	$901,654
	Total Annualized Cost	$753,802	$2,085,738	$3,519,262
	Tons SO_2 Removed	179	223	343
	Average Cost Effectiveness ($/ton)	$4,218[3]	$9,337[3]	$10,275
	Incremental Cost Effectiveness ($/ton)	$4,218[3]	$29,813	$12,033

Notes:

(1) Based on a capital recovery factor of 0.11683 for 15 years at 8%.

(2) Fixed and variable O&M costs based on Enviroplan's estimates of the additional reagent and other related costs required to achieve 70% control (relative to the existing 50% control baseline), using a coal having an uncontrolled SO_2 emission rate of 0.60 lb/MMBtu (see response 2 to Sierra Club comments).

(3) Annual and incremental costs for the dry sorbent injection optimization control scenario (70% control) were calculated relative to the existing (baseline) dry sorbent control scenario (50% control). Average costs for other options calculated relative to the existing controlled baseline.

(4) Based on a capital recovery factor of 0.17401 for 8 years at 8%.

(5) Results presented for informational purposes only, and reflects an update of the April 2009 Findings Report, i.e., no constraint on remaining life expectancy for Healy 1 and each add-on control option is assumed to have a useable lifetime of 15 years.

Summary of NO_x Cost-Effectiveness Calculations Based on an 8-Year Remaining Lifetime for Healy Unit 1

Remaining Useful Life	Cost Item	Optimize Existing LNB w/OFA	SNCR	ROFA	ROFA/ Rotamix	SCR[1]
15 Years[4]	Total Installed Capital Cost	$20,000 ($1/kw)	$2,538,900 ($102/kw)	$4,572,000 ($183/kw)	$6,912,000 ($276/kw)	$21,860,887 ($874/kw)
	Capital Recovery	$2,337[2]	$296,620[2]	$534,147[2]	$807,529[2]	$2,554,007[2]
	Fixed and Variable O&M Costs	$0	$122,191	$138,852	$287,309	$1,125,172
	Total Annualized Cost	$2,337	$418,811	$672,997	$1,094,838	$3,679,179
	Tons NO_x Removed	74	134	194	253	313
	Average Cost Effectiveness ($/ton)	$31	$3,125	$3,476	$4,325	$11,765
	Incremental Cost Effectiveness ($/ton)	$31	$6,992	$4,267	$7,082	$43,385
8 Years	Total Installed Capital Cost	$20,000 ($1/kw)	$2,538,900 ($102/kw)	$4,572,000 ($183/kw)	$6,912,000 ($276/kw)	$21,860,887 ($874/kw)
	Capital Recovery	$3,480[3]	$441,794[3]	$795,574[3]	$1,202,757[3]	$3,804,013[3]
	Fixed and Variable O&M Costs	$0	$122,191	$138,852	$287,309	$1,125,172
	Total Annualized Cost	$3,480	$563,985	$934,426	$1,490,066	$4,929,185
	Tons NO_x Removed	74	134	194	253	313
	Average Cost Effectiveness ($/ton)	$47	$4,208	$4,827	$5,886	$15,762
	Incremental Cost Effectiveness ($/ton)	$47	$9,409	$6,219	$9,328	$57,734

Notes:

(1) Costs and tons of NO_x removed based on GVEA's estimates for the 0.28 lb/MMBtu scenario as presented in its June 15, 2009 letter to ADEC from Kristen DuBois of GVEA.
(2) Based on a capital recovery factor of 0.11683 for 15 years at 8%.
(3) Based on a capital recovery factor of 0.17401 for 8 years at 8%.
(4) Results presented for informational purposes only, and reflects an update of the April 2009 Findings Report, i.e., no constraint on remaining life expectancy for Healy 1 and each add-on control option is assumed to have a useable lifetime of 15 years.

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
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August 18, 2008

Mr. Chris Drechsel
Senior Environmental Professional
Tesoro Companies, Inc.
3450 S. 344th Way, Suite 201
Auburn, WA 98001-5931

Subject: Approval of BART Exemption Analysis for Tesoro Kenai Refinery

Dear Mr. Drechsel:

The Alaska Department of Environmental Conservation (Department) is approving the Best Available Retrofit Technology (BART) exemption analysis submitted by Tesoro Alaska Company (Tesoro) for the Tesoro Kenai Refinery. The May 2008 analysis adequately shows that Tesoro's BART-eligible sources are not reasonably anticipated to cause or contribute to any impairment of visibility in the Denali National Park or Tuxedni Wilderness Class I areas. Tesoro has therefore demonstrated that the Tesoro Kenai Refinery is not subject to BART and as such, is *not* required to submit a BART control analysis under 18 AAC 50.260(d) - (e). The Department's detailed findings regarding Tesoro's exemption analysis are enclosed.

Please note that the Department's decision is subject to public comment and approval by the U.S. Environmental Protection Agency (EPA). The Department must include all BART decisions in the regional haze component of the State Implementation Plan (SIP), per Section 169A of the Clean Air Act. The Department must also provide public notice for the regional haze SIP proposal, per state and federal requirements. Once the comment period is completed, the Department will submit the proposal, or a modified version thereof, to EPA for review and approval. While the Department does not expect adverse comments from the public or EPA, receipt of such may be cause for reopening the Department's decision and asking Tesoro to revise the analysis (if warranted).

For public record purposes, Tesoro used a more refined analysis than what was previously used by the Western Regional Air Partners (WRAP) – Regional Modeling Center (RMC). The most notable improvement was the use of a 3-year, 5-kilometer (km) MM5 meteorological data set; rather than the 1-year, 15-km MM5 meteorological data set used by WRAP. The Department approved the new MM5 data set on November 30, 2007.

Tesoro conducted their visibility modeling analysis in accordance with Department approved modeling protocols, as required under 18 AAC 50.260(c)(3)(A) and (h)(3)(B). These protocols, and the Department approval dates, are summarized below:

- A revised CALMET protocol (for processing the new MM5 data), which the Department approved on December 19, 2007; and
- A revised CALPUFF protocol (for conducting the actual visibility analysis), which the Department approved on April 17, 2008. Changes to the CALPUFF protocol included use of the current regulatory version of the CALPUFF modeling system (Version 5.8), rather than the non-regulatory version previously used by WRAP (Version 6.112).

Tesoro's revisions allowed for a more refined and robust analysis than the analysis previously conducted by WRAP. The Department therefore allowed Tesoro to compare the 98th percentile change in visibility, rather than the maximum change in visibility – as used by WRAP, to the 0.5 deciview threshold. Using this metric, the largest visibility impact at Denali is 0.046 deciviews, and the largest visibility impact at Tuxedni is 0.425 deciviews. In both cases, these impacts are less than the 0.5 deciview threshold.

Tesoro's May 2008 submittal meets the BART exemption requirements of 18 AAC 50.206(c). Today's letter provides the notification requirements listed in 18 AAC 50.260(c)(4) and (c)(6).

Sincerely,

John Kuterbach
Program Manager

Enclosure: Findings Report – Tesoro BART Exemption Modeling

cc: Ken Richmond, Geomatrix Consultants, Inc. (via e-mail)
Tim Allen, FWS (via e-mail)
John Notar, NPS (via e-mail)
Herman Wong, EPA Region 10 (via e-mail)
John Kuterbach, ADEC/APP (via e-mail)
Tom Turner, ADEC/APP (via e-mail)
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ENVIROPLAN CONSULTING

Findings Report
Tesoro Alaska Company - Tesoro Kenai Refinery
Best Available Retrofit Technology (BART) Exemption Modeling

Prepared for

State of Alaska
Department of Environmental Conservation
Division of Air Quality

ADEC Contract No. 18-3001-17
NTP No. 18-3001-17-5A

Prepared by
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Enviroplan Consulting Project No. 209915.15
August 12, 2008

EXECUTIVE SUMMARY

Enviroplan Consulting (Enviroplan) was retained by the Alaska Department of Environmental Conservation (Department) to review a Best Available Retrofit Technology (BART) exemption modeling analysis submitted by Tesoro Alaska Company for their Kenai Refinery. The exemption analysis was prepared on behalf of Tesoro by their consultant, Geomatrix, pursuant to the Federal Regional Haze Rule, 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule*; and the Department's regulation relating to BART, 18 AAC 50.260. The Department previously approved, on April 17, 2008, a modeling protocol submitted by Tesoro regarding the approach they would use in conducting the exemption analysis. As described in this report, Tesoro has followed their modeling protocol and they have submitted an acceptable exemption analysis.

Under the Federal Regional Haze Rule, States and other air pollution control authorities are required to identify and list "BART-eligible sources". For the Tesoro Kenai Refinery, the Department has determined that thirteen (13) BART-eligible units exist at the plant. These units include two crude heaters, three preheaters, one hot oil heater, two steam generators, and five engines. Two of the five engines (unit IDs 38 and 39) are restricted by condition 15 of existing Title V Permit No. 035TVP01, such that only one engine can operate at a time. As a result, only 12 of the 13 BART-eligible sources are operational at any time and this configuration has been modeled by Tesoro in the BART exemption study.

The Department's BART regulations allow sources to request an exemption from BART, if they can demonstrate that an affected BART eligible source or group of sources are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area. If such is demonstrated, the source does not need to make a BART determination for that affected source or group of sources. Tesoro submitted such a request on May 16, 2008.

The following sections of this document provide the detailed findings associated with the Tesoro BART exemption analysis. As indicated above, the Tesoro analysis is consistent with their approved modeling protocol.

INTRODUCTION

As summarized by Tesoro in their exemption analysis report, and as reflected by the Department in the scope of work to this project, during 2007 the Department developed a list of Alaska BART-eligible sources based on the federal BART guidelines, conducted preliminary dispersion modeling of these BART-eligible sources, and released the results of a regional BART screening analysis that included all BART-eligible sources in the state. This modeling was completed by the Western Regional Air Partnership (WRAP) - Regional Modeling Center (RMC). The simulations were done using the CALPUFF modeling system and a single year, 2002, of processed MM5 CALMET data. The simulations were performed to evaluate predicted impacts of visibility in two Alaska PSD Class I areas, the Tuxedni National Wildlife Refuge designated as a National Wilderness Area (Tuxedni) and the Denali National Park including the Denali Wilderness but excluding Denali National Preserve (Denali). BART-eligible sources are exempt from BART if the daily visible impacts at a Class I area are below screening criteria set by the Department, EPA, and the Federal Land Managers (FLMs). Pursuant to 18 AAC 50.260(q)(4), a 0.5 or greater daily deciview change when compared against natural conditions is considered to "cause" visibility impairment.

RMC used the CALPUFF modeling system to assess visible impacts for BART-eligible emission units based on the 15 kilometer (km) MM5 output data for 2002. The CALPUFF model grid spacing was 2 km, significantly different than the MM5 grid spacing of 15 km. In addition, because only one year was simulated, BART exemption simulations performed by RMC used the highest modeled visibility degradation, not the 98th percentile as allowed under EPA guidance. The 12 BART-eligible emission units located at the Tesoro Refinery were determined by RMC to have modeled daily visibility impacts in excess of the 0.5 deciview metric and, therefore, subject to BART control requirements.

The above notwithstanding, Tesoro has requested approval for a BART exemption supported by a more refined modeling analysis using available MM5 data that has been refined and expanded to consist of a 5-kilometer (km), 3-year data set, as compared to the 15-km, 1-year MM5 data set used by WRAP. The Department approved both the new MM5 data set on November 30, 2007; and a revised CALMET modeling protocol on December 19, 2007 for the meteorological data processing. Tesoro submitted a CALPUFF modeling protocol on January 22, 2008, and a minor protocol revision on January 25, 2008, to describe the proposed refined BART exemption visibility modeling analysis planned for their Kenai Refinery BART-eligible sources. The Department approved the protocol on April 17, 2008. Tesoro submitted their exemption analysis under a May 16, 2008 cover letter. The modeling analysis and report have been prepared by Geomatrix on behalf of Tesoro. Geomatrix also prepared the Department approved MM5 and 3-year meteorological data set utilized in this study.

The following sections of this report present the review findings pertaining to the Tesoro exemption study and the related CALPUFF modeling files. The review has been performed to determine whether the study conforms to the above specified protocol documents, and related rules and regulatory guidance, including 18 AAC 50.260, *Guidelines for best available retrofit technology under the regional haze rule;* 40 CFR 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule;* and U.S. EPA's *Guidance for Estimating*

Natural Visibility Conditions Under the Regional Haze Rule (EPA-454/B-03-005, September 2003).

FINDINGS

A review has been conducted of the BART exemption visibility impact analysis performed by Geomatrix on behalf of Tesoro for their Kenai Refinery BART-eligible sources. A discussion of each section of the Tesoro report, and any findings associated with the review of that section and the associated CALPUFF modeling data, procedures and files, are presented below.

Section 1 - Introduction:

This section of the study report provides a concise overview of the history, regulatory basis and conclusions associated with the BART exemption modeling analysis. No comments or findings that affect the conclusions of the study result from the review of this section of the report.

Section 2 - CALPUFF Modeling Procedures:

This section of the study report is divided into six (6) subsections that pertain to the CALPUFF modeling procedures utilized by Tesoro (Geomatrix) in the visible impacts analysis. The following presents a summary and any findings associated with each of these six sections.

Section 2.1 - CALPUFF Version:

This section of the study report specifies that CALPUFF version 5.8, level 070623 has been used in the exemption study. This is the current EPA approved version of this model and its use is consistent with the protocol document. No comments or findings result from the review of this section of the report.

Section 2.2 - CALMET Dataset:

This section of the study report describes the CALMET version used to prepare the 2002, 2003 and 2004 meteorological data set used in this study (i.e., CALMET version 5.8, level 070623). Use of the new 3-year MM5 data set for the same period is likewise indicated in this section. This section is considered informational only, as the MM5 and CALMET data were separately approved for use by the Department prior to submittal of the January 2008 protocol document and the May 2008 study report. No comments or findings result from the review of this section of the report.

Section 2.3 - CALPUFF Modeling Domain:

This section of the study report specifies that a CALPUFF computational domain has been used that is fully consistent with the CALMET domain (540 km x 650 km, 2 km horizontal grid spacing). The domain includes the refinery and the two subject Class I areas (Denali National Park and Tuxedni Wilderness Area), and extends at least 50km beyond the Class I areas to account for possible plume recirculation. This domain is consistent with the protocol document. No comments or findings result from the review of this section of the report.

Section 2.4 - Emission Rates and Stack Parameters:

This section of the study report describes the emissions inventory data used in the modeling analysis for the Kenai Refinery BART-eligible sources. The following summarizes the information presented in Section 2.4 as used in the CALPUFF input files, and any findings relating to review of this information:

- BART eligible unit NOx, SO2 and PM10 emission rates, which are summarized in Table 1 of the Tesoro study report, are consistent with the emission rates both proposed in the protocol document and provided by Tesoro to the Department for use in the WRAP CALPUFF visibility modeling.

- Tesoro Emission Unit ID 39 (Engine (P708B)) is a BART-eligible unit that has not been included in the modeling analysis since condition 15 of existing Title V Permit No. 035TVP01 requires that only one of the two identical engines, ID 38 or 39, operate at a time. Emission Unit ID 38 has been included in the CALPUFF input file emissions inventory.

  It is noted that the NOx, SO2 and PM10 emission rates for ID 38 found in the study report and used in the CALPUFF modeling are greater than those found in the September 12, 2006 compilation of BART-eligible units' stack parameters prepared by the Department. Use of the higher emission rates, which are believed to reflect daily maximum potential to emit instead of maximum actual emissions, is considered to be conservative since it results in maximum predicted source visible impacts which, in turn, produces greater changes in visible impacts when compared to natural background conditions (i.e., deciviews).

- BART eligible unit stack exit parameters, which are summarized in Table 2 of the Tesoro report, are consistent with both the emission rates proposed in the protocol document and the rates Tesoro provided to the Department for use in the CALPUFF visibility modeling performed by WRAP.

- BART eligible unit stack locations, which are summarized in Table 3 of the Tesoro report, are consistent with the locations specified in the protocol document, which have been provided by Tesoro to replace the single location used to represent each of the 12 sources in the WRAP modeling study.

- For each BART eligible source, all PM10 emitted has been assumed as PM2.5, which is consistent with the protocol document. Also, both the PM2.5 speciation and the percent of PM2.5 represented by each species are consistent with the protocol document, which indicates the PM2.5 fractions are based on profiles recommended by the U.S. EPA for the CMAQ model. This information is summarized in Table 4 of the Tesoro report.

In summary, the data described in this section of the study report and used in the CALPUFF input files are consistent with the protocol document. There are no additional comments or findings on the review of this section of the report.

Section 2.5 - CALPUFF Options:

This section of the study report describes the CALPUFF modeling methods and the related model input options selected for use in this study. This information has been reviewed for consistency with the previously specified protocol and related guidance documents, and the same consistency check has been made to the related CALPUFF model input files. Detailed information supporting this review has been compiled in accompanying Microsoft Excel spreadsheets. The spreadsheets present modeling related information used by Tesoro in this exemption analysis, as well as comparative BART modeling information used by WRAP. The following summarizes the information presented in Section 2.5 as used in the CALPUFF input files, and any findings relating to review of this information:

- CALPUFF modeling performed for each of three years (2002 - 2004) with Department approved CALMET meteorological data prepared by Geomatrix using revised MM5 data. For modeled years 2003 and 2004, the modeling commenced 48 hours prior to the start of each year to allow for puff carry-over from the previous year.
- EPA-approved CALPUFF version 5.8, level 070623
- EPA CASTNET hourly ozone data from Denali, using 40 ppb default for missing hours
- A background ammonia concentration of 0.5 ppb (increased from 0.1 ppb as initially proposed in the protocol document, which is compliant with comments made by the Department in the April 17, 2008 protocol approval letter)
- Regulatory default model options when such options are specified
- National Park Service discrete receptor locations and elevations for Denali National Park and the Tuxedni Wilderness (http://www2.nature.nps.gov/air/maps/Receptors/index.cfm)
- Aerodynamic building downwash not used in the modeling analysis
- CALPUFF computational domain consistent with the CALMET meteorological domain (NX=270, NY=325)

In summary, the data and model option selections described in this section of the study report and used in the CALPUFF input files are consistent with the protocol document. Also, the procedures used in this study are similar to the WRAP analysis for this plant, except that the Tesoro analysis uses the current EPA approved version of CALPUFF; three-years of approved refined meteorological data; and speciation of PM2.5 (as 100% PM10) based on approved profiles for the source equipment types. There are no additional comments or findings on the review of this section of the report.

Section 2.6 - CALPOST Procedures:

This section of the study report describes the CALPUFF post-processing methods using CALPOST and the related model input options selected for this study. This information has been reviewed for consistency with the previously specified protocol and related guidance documents, and the same consistency check has been made to the related CALPOST model input files. Detailed information supporting this review has been compiled in accompanying Microsoft Excel spreadsheets. The spreadsheets present modeling related information used by Tesoro in this exemption analysis, as well as comparative BART modeling information used by WRAP. The following summarizes the information presented in Section 2.6 as used in the CALPOST input files, and any findings relating to review of this information:

- EPA-approved CALPUFF version 5.6494, level 070622
- Particle growth curve f(RH) for hygroscopic species based on EPA (2003) f(RH) tabulation
- CALPOST default extinction efficiencies were used for PM fine (PMF), PM coarse (PMC), ammonium sulfate, ammonium nitrate, organic carbon (OC), and elemental carbon (EC)
- Background extinction and change to extinction has been calculated using the recommended CALPOST Method 6 (MVISBK=6).
- Monthly relative humidity adjustment factors specific to each Class I area have been taken from Table A-3 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003), as required. It is noted that WRAP used the same Table A-3 values. While 40 CFR 51, Appendix Y is not specific as to which table is to be used for BART modeling, it is believed Table A-2 is the preferred table since the title to the table indicates "recommended" monthly values. However, since the f(RH) values in Tables A-2 and A-3 differ by only one-one hundredth when they differ at all, either table is acceptable for use in the study.
- Annual average natural background aerosol concentrations have been taken from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003), as required. These are the same annual average background values used by WRAP.
- Since Method 6 (MVISBK=6) of CALPOST version 5.6394 has been used by Tesoro in this exemption study, the "old" IMPROVE equation is reflected in the study results. While a "new" IMPROVE equation has been developed, the "old" equation is consistent with the approved modeling protocol as well as the WRAP study.

In summary, the information described in this section of the study report and similarly used in the CALPOST input files is consistent with the protocol document. Also, the procedures used in this study are similar to the WRAP analysis for this plant as indicated above. There are no additional comments or findings on the review of this section of the report.

Section 3 - Modeling Results:

This section of the study report summarizes the results of the exemption analysis. As supported in EPA's BART rules and guidelines, and as specified in the protocol document, a successful demonstration of insignificance for this 3-year visible impacts modeling study is based on the use of the 98th percentile change to the daily Haze Index (HI) expressed in units of deciviews. The "significance" metric against which the predicted values of delta-HI are compared is a 0.5 daily deciview change.

Table 5 of the Tesoro study report presents a summary of the 98th percentile modeling results at each Class I area for each year of modeling and over the entire three-year period. Further, as requested by the Department and submitted by Tesoro on May 19, 2008, additional results tables have been provided. These supplemental tables present the visibility results associated with the top 8 days for the individual years of modeling, and the top 22 days for the three years of modeling combined, rather than only the 98th percentile results of Table 5. Plots and graphical depictions relating to the CALPUFF modeling results are also presented in the study report. The CALPUFF modeling results demonstrate compliance with the 0.5 daily deciview metric for both Class I areas and all three years of modeling.

Findings Review Conclusions

A detailed review of the Tesoro BART-eligible exemption analysis has been conducted for the Kenai Refinery. It has been determined that the BART exemption analysis has been conducted in conformance with the January 2008 protocol document submitted to, and approved by, the Department on April 17, 2008. Overall, Tesoro has successfully demonstrated the visibility analysis conducted for their BART eligible sources meets federal and state provisions on exempting these units from otherwise applicable BART control requirements.

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF AIR QUALITY
AIR PERMITS PROGRAM

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October 3, 2008

Yelena Saville
Anchorage Municipal Light & Power
1200 East First Ave.
Anchorage, AK 99501-1685

Subject: Approval of BART Exemption Analysis for Anchorage Municipal Light & Power

Dear Ms. Saville:

The Alaska Department of Environmental Conservation (Department) is approving the *revised* Best Available Retrofit Technology (BART) exemption analysis submitted by Anchorage Municipal Light & Power (ML&P) under an August 25, 2008 cover letter. The revised analysis adequately shows that ML&P's BART-eligible sources are not reasonably anticipated to cause or contribute to any impairment of visibility in the Denali National Park or Tuxedni Wilderness Class I areas. ML&P has therefore demonstrated that the George Sullivan Plant 2 is not subject to BART and as such, is *not* required to submit a BART control analysis under 18 AAC 50.260(d) - (e). The Department's detailed findings regarding ML&P's revised exemption analysis are enclosed.

Please note that the Department's decision is subject to public comment and approval by the U.S. Environmental Protection Agency (EPA). The Department must include all BART decisions in the regional haze component of the State Implementation Plan (SIP), per Section 169A of the Clean Air Act. The Department must also provide public notice for the regional haze SIP proposal, per state and federal requirements. Once the comment period is completed, the Department will submit the proposal, or a modified version thereof, to EPA for review and approval. While the Department does not expect adverse comments from the public or EPA, receipt of such may be cause for reopening the Department's decision and asking ML&P to revise the analysis (if warranted).

For public record purposes, ML&P used a more refined analysis than what was previously used by the Western Regional Air Partners (WRAP) – Regional Modeling Center (RMC). The most notable improvement was the use of a 3-year, 5-kilometer (km) MM5 meteorological data set; rather than the 1-year, 15-km MM5 meteorological data set used by WRAP. The Department approved the new MM5 data set on November 30, 2007.

ML&P conducted their visibility modeling analysis in accordance with Department approved modeling protocols, as required under 18 AAC 50.260(c)(3)(A) and (h)(3)(B). These protocols, and the Department approval dates, are summarized below:

- A revised CALMET protocol (for processing the new MM5 data), which the Department approved on December 19, 2007; and
- A revised CALPUFF protocol (for conducting the actual visibility analysis), which the Department approved on January 8, 2008. Changes to the CALPUFF protocol included use of the current regulatory version of the CALPUFF modeling system (Version 5.8), rather than the non-regulatory version previously used by WRAP (Version 6.112).

ML&P's revisions allowed for a more refined and robust analysis than the analysis previously conducted by WRAP. The Department therefore allowed ML&P to compare the 98th percentile change in visibility, rather than the maximum change in visibility – as used by WRAP, to the 0.5 deciview threshold. ML&P provided an even more robust analysis by providing the visibility impacts using two different approaches, commonly known as: the "old" IMPROVE equation; and the "new" IMPROVE equation. The Department focused their review on the "old" equation since this is the approach being used by most BART sources in Alaska. However, the largest visibility impact using *either* approach is 0.48 deciviews at Denali ("old" equation result) and 0.42 deciviews at Tuxedni ("new" equation result). In all cases, the impacts are less than the 0.5 deciview threshold.

ML&P's August 2008 submittal meets the BART exemption requirements of 18 AAC 50.206(c). Today's letter provides the notification requirements listed in 18 AAC 50.260(c)(4) and (c)(6).

Sincerely,

John Kuterbach
Program Manager

Enclosure: Findings Report: ML&P BART Exemption Modeling – Revised

cc: Al Trbovich, Hoefler Consulting Group (via e-mail)
Tim Allen, FWS (via e-mail)
John Notar, NPS (via e-mail)
Herman Wong, EPA Region 10 (via e-mail)
Tom Turner, ADEC/APP (via e-mail)
Rebecca Smith, ADEC/APP (via e-mail)
Alan Schuler, ADEC/APP (via e-mail)
Cynthia Williams, ADEC/ANP&MS (via e-mail)

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ENVIROPLAN CONSULTING

Findings Report
Anchorage Municipal Light & Power (ML&P)
Best Available Retrofit Technology (BART) Exemption Modeling - Revised

Prepared for

State of Alaska
Department of Environmental Conservation
Division of Air Quality

ADEC Contract No. 18-3001-17
NTP No. 18-3001-17-6B

Prepared by
Enviroplan Consulting
Edgewater Commons II
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Enviroplan Consulting Project No. 209916.15
October 2, 2008

EXECUTIVE SUMMARY

Enviroplan Consulting (Enviroplan) was retained by the Alaska Department of Environmental Conservation (Department) to review a revised Best Available Retrofit Technology (BART) exemption modeling analysis submitted on August 25, 2008 by Anchorage Municipal Light & Power (ML&P). The BART exemption analysis revises an initial exemption analysis submitted by ML&P on March 10, 2008. As described in this report, ML&P has submitted an exemption analysis that complies with 18 AAC 50.260(c)(3) and that adequately demonstrates that their BART-eligible sources are not reasonable anticipated to cause or contribute to any impairment of visibility in the Denali National Park or Tuxedni Wilderness Class I areas.

The BART exemption analyses (initial and revised) were prepared by ML&P pursuant to the Federal Regional Haze Rule, 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule*; and the Department's regulation relating to BART, 18 AAC 50.260.

Under the Federal Regional Haze Rule, states are required to identify and list "BART-eligible sources." For ML&P, the Department has determined that the ML&P George M. Sullivan Generation Plant Two, has two BART-eligible units. These units are the two combustion turbines identified as the Westinghouse W-251-B2 turbine (Title V Permit Emission Unit 1, ML&P ID GTG-5) and the General Electric Frame 7 – PG7981 turbine (Title V Permit Emission Unit 2, ML&P ID GTG-7). The Department's BART regulations allow sources to request an exemption from BART, if they can demonstrate that the affected BART eligible source or group of sources are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area. If such is demonstrated, the source does not need to make a BART determination for that affected source or group of sources.

The Department approved on January 8, 2008 a modeling protocol submitted by ML&P regarding the approach they would use in conducting the exemption analysis. The March 2008 BART exemption analysis was reviewed by Enviroplan during July 2008. In general, Enviroplan determined that ML&P did not *fully* follow their modeling protocol, as required under 18 AAC 50.260(c)(3)(A), and therefore, had *not* submitted an acceptable exemption analysis. Enviroplan described the deficiencies in an August 6, 2008 Findings Report (Project No. 209914.15). The Department communicated the results to ML&P on August 7, 2008. Immediately thereafter, the Department agreed to a request made by ML&P to correct the study deficiencies and submit a revised BART exemption analysis.

The following sections of this document provide the detailed findings associated with the revised ML&P BART exemption analysis. Overall, the revised visibility analysis is consistent with the approved modeling protocol and it adequately addresses the deficiencies noted in the August 6, 2008 Findings Report.

INTRODUCTION

As summarized by ML&P in their exemption analysis, and as reflected by the Department in the scope of work to this project, during 2007 the Department developed a list of Alaska BART-eligible sources based on the federal BART guidelines, conducted preliminary dispersion modeling of these BART-eligible sources, and released the results of a regional BART screening analysis that included all BART-eligible sources in the state. This modeling was completed by the Western Regional Air Partnership (WRAP) - Regional Modeling Center (RMC). The simulations were done using the CALPUFF modeling system and a single year, 2002, of processed MM5 CALMET data. The simulations were performed to evaluate predicted impacts of visibility in two Alaska PSD Class I areas, the Tuxedni National Wildlife Refuge designated as a National Wilderness Area (Tuxedni) and the Denali National Park including the Denali Wilderness but excluding Denali National Preserve (Denali). BART-eligible sources are exempt from BART if the daily visible impacts at a Class I area are below screening criteria set by ADEC, EPA, and the Federal Land Managers (FLMs). Pursuant to 18 AAC 50.260(q)(4), a 0.5 or greater daily deciview change when compared against natural conditions is considered to "cause" visibility impairment.

RMC used the CALPUFF modeling system to assess visible impacts for BART-eligible emission units based on the 15 kilometer (km) MM5 output data for 2002. The CALPUFF model grid spacing was 2 km, significantly different than the MM5 grid spacing of 15 km. In addition, because only one year was simulated, BART exemption simulations performed by RMC used the highest modeled visibility degradation, not the 98th percentile as allowed under EPA guidance. The two ML&P combustion turbines were determined by WRAP to have modeled visibility impacts in excess of the 0.5 deciview metric and, therefore, subject to BART control requirements.

The above notwithstanding, ML&P has requested approval for a BART exemption supported by a more refined modeling analysis using available MM5 data that has been refined and expanded to now consist of a 5-kilometer (km), 3-year data set, as compared to the 15-km, 1-year MM5 data set used by WRAP. The Department approved both the new MM5 data set on November 30, 2007; and a revised CALMET modeling protocol for processing the meteorological data on December 19, 2007. ML&P submitted a CALPUFF modeling protocol to describe the proposed refined BART exemption visibility modeling analysis on October 15, 2007, with clarifications/revisions submitted on December 31, 2007 in response to Department comments and questions issued on December 19, 2007. The Department approved the protocol, as revised, on January 8, 2008. ML&P submitted their refined exemption analysis under a March 10, 2008 cover letter, with supplemental information submitted on May 5, 2008 that addressed initial Federal Land Manager (FLM) questions issued on April 25, 2008. Enviroplan Consulting, as a contractor to the Department, reviewed the ML&P exemption analysis and reported study deficiencies to the Department on August 6, 2008. The Department approved an ML&P request to revise their initial exemption analysis, and such was resubmitted on August 25, 2008.

The following sections of this report present the review findings pertaining to both the ML&P revised exemption study and the related CALPUFF modeling files. Enviroplan performed the review to determine whether ML&P adequately addressed the deficiencies identified in the August 6, 2008 Findings Report; and if the visibility analysis conforms to the above specified protocol documents and the related rules and regulatory guidance, including 18 AAC 50.260, *Guidelines for best available retrofit technology under the regional haze rule;* 40 CFR 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule,* and U.S. EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). Review of the ML&P study has focused on both the modeled emission rates used for the affected units, since ML&P did not propose these values in their modeling protocol; and the procedures, methods and data (other than emission rates) utilized in the exemption analysis.

FINDINGS

Source Stack Parameters

Findings associated with review of the initial (March 10, 2008) BART exemption study indicated the stack parameters (height, base elevation, inner diameter, exit velocity and exit temperature) applied by ML&P in their exemption modeling differed from the parameters used by WRAP. With the exception of the base elevations, ML&P has revised the source stack parameters in the revised exemption analysis to be consistent with those used by WRAP in the CALPUFF modeling analysis. ML&P has explained the base elevations differ from WRAP due to ML&P's use of site-specific drawings and finished floor elevation surveys, and this explanation is acceptable. Copies of the drawings were included in the revised study report. Use of the revised data is consistent with the January 8, 2008 Department approved protocol document.

Source Emission Rates

The August 6, 2008 Findings Report cited source emission rate issues that required revision and/or further explanation. These issues have been addressed satisfactorily by ML&P in the revised exemption study as follows:

- In the initial exemption study, ML&P modeled both turbines using an actual daily dual fuel usage scenario consisting of distillate oil firing for 15 minutes and natural gas firing for 23 hours and 45 minutes. However, based on two 30-minute distillate firing events for turbine GTG-5, the Department required ML&P to model GTG-5 under a daily dual fuel usage scenario reflective of 30-minutes of distillate firing. The actual daily dual fuel usage scenario for turbine GTG-7 was determined to be acceptable by the Department. This notwithstanding, ML&P has revised the emission rates such that both units are assumed to fire distillate oil for 30-minutes. This scenario is acceptable and conservative since it may result in higher predicted source visible impacts than would otherwise occur with GTG-7 unchanged at 15-minutes per day of distillate oil firing.
- The August Findings Report requested that the daily NOx and PM2.5 emission rates, which were computed using AP-42 emission factors, be revised to reflect the previously provided manufacturer and source test data (i.e., the values contained in ML&P's November 1997 Title V operating permit application and used by WRAP). ML&P has revised the pollutant emission rates. The revised PM2.5 emission rates are fully consistent with the November 1997 Title V permit application and WRAP modeled emission rates. For GTG-5, ML&P revised the NOx emission rate consistent with the Title V and WRAP NOx emission rate, and then increased that rate by 1.1 g/s to account for the additional 15-minutes of distillate firing described above (i.e., total NOx rate of 39.7 g/s). This approach is conservative since the WRAP emission rate already reflects 24-hours of unit operation, but emissions from 15-minutes of additional distillate oil firing are nonetheless added to the WRAP emission rate.

For GTG-7, ML&P has continued to use AP-42 as the basis for the modeled NOx emission rate. However, the AP-42 based NOx emission rate (43.2 g/s) exceeds the WRAP modeled NOx emission rate (40.62 g/s). Further, ML&P has increased the AP-42 emission rate by 2.5 g/s to account for 15-minutes of additional distillate firing which is not required for GTG-7 (total NOx rate of 45.7 g/s). Therefore, ML&P's use of NOx emission rates greater than the rates used in the WRAP analysis is conservative and acceptable.

- Daily SO2 emission rates (pound/day) were computed in the initial exemption study using a stated fuel gas sulfur content of 0.2 ppmv. The August Findings Report specified that ML&P should instead use the protocol-approved WRAP emission rates for SO2, as determined from a fuel gas sulfur content of 80 ppmv of H2S based on Title V Permit No. 203TVP01, Condition 6.3; or they should provide documentation to confirm the actual fuel gas sulfur content. The revised ML&P study report has included a natural gas composition report that indicates a fuel gas sulfur content of 2 ppm by weight, not 0.2 ppmv as indicated in the initial ML&P study report (2 ppmw sulfur would be equivalent to about 1.01 ppmv of H2S). Irrespective of the composition report, ML&P has revised the daily (and modeled) SO2 emission rates to not only reflect the higher WRAP SO2 emission rates (i.e., Title V Permit SO2 emission rates based on 80 ppmv H2S), but ML&P has also increased these rates to account for an additional 15-minutes of distillate oil firing as discussed above. A table comparing the modeled SO2 emission rates (g/s) used in the WRAP and revised ML&P studies is presented below. It is noted that, in addition to modeling SO2 emissions, ML&P also determined and modeled sulfate emissions (see discussion below), where such emissions were not considered by WRAP. The SO2 emission rates used in the revised exemption study are both conservative and consistent with the recommendations of the August Findings Report.

Emission Unit	**Modeled SO2 Emission Rate (g/s)**	
	WRAP Study	**Revised ML&P Study**
GTG-5 Gas Turbine Generator	0.66	0.67
GTG-7 Gas Turbine Generator	2.36	2.38

- The initial exemption study report provided actual daily NOx, PM2.5 and SO2 emission rates for the turbines expressed in units of lb/day and g/s. Conversion of the lb/day emission rates to units of g/s were not readily reproducible. The revised exemption study has corrected the pollutant emission rates when expressed in units of g/s.

- The August 6, 2008 Findings Report cited issues associated with the use of the National Park Service (NPS) particulate speciation profiles (i.e., http://www.nature.nps.gov/air/permits/ect/index.cfm) for a gas fired turbine. These issues have been satisfactorily addressed by ML&P in the revised exemption study as follows:

  - In both the initial and revised analyses the NPS profiles were not used to speciate particulate matter; instead total PM2.5 emission rates for each turbine were modeled in CALPUFF, consistent with the WRAP RMC modeling. ML&P then applied the maximum default particulate species extinction efficiency (i.e., 10 m^2/g for elemental carbon) to their predicted PM2.5 concentrations (i.e., CALPOST - Input Group 2), maximizing both the predicted source visible impacts and the change in extinction values (delta deciviews). While it was noted in the August Findings Report that ML&P could apply the NPS PM2.5 species profiles in their revised CALPOST modeling, ML&P has continued to apply the 10 m^2/g (elemental carbon) extinction efficiency to total PM2.5 predicted concentrations. This continues to conservatively maximize the change in extinction values (delta deciviews) and it is acceptable for this study.

- The CALPUFF input file at Subgroup 3a in the initial exemption analysis specified that SO4 was not emitted by the source, yet Table 1 of the initial study report provided emission rates for SO4 determined using the NPS profiles. This inconsistency has been corrected in the revised exemption study: the CALPUFF input files utilize the correct SO4 emission rates, as shown in Table 1 of the revised study report and described in the bullet below.
- The August Findings Report indicated that ML&P used only the NPS profile for a gas-fired turbine to determine the SO2 and SO4 emission rates, where the respective profiles for gas and oil should have been applied. Both NPS profiles for gas and oil combustion have been applied in the revised exemption study. The corrected SO2 and SO4 emission rates, which also reflect 80 ppmv H2S and 30-minute oil firing as discussed above, were used by ML&P in the revised modeling analysis.

<u>CALPUFF and CALPOST Modeling Inputs and Study Results</u>
The August 6, 2008 Findings Report cited CALPUFF/CALPOST model input file issues that required revision and/or further explanation. These issues have been addressed satisfactorily by ML&P in the revised exemption study as summarized below. Information supporting this review has been compiled in accompanying Microsoft Excel spreadsheets for both CALPUFF and CALPOST. The spreadsheets present modeling related information used by ML&P in the initial and revised exemption analyses, as well as comparative BART modeling information used by WRAP.

- CALPUFF modeling files:
  - In the initial exemption study, the full year run length setting (Input Group 0, parameter IRLG) for each year modeled (2002, 2003 and 2004) was shortened by 10 hours per year (i.e., 8750 instead of 8760 for 2002, 2003; and 8774 instead of 8784 for 2004). The revised exemption study corrects the CALPUFF input files to reflect a full year of modeling for each of the three years analyzed in the exemption study.
  - EPA-approved CALPUFF version 5.8, level 070623; and CALPOST version 5.6394, level 070622 (unchanged from initial exemption study and this is the correct setting).
  - EPA CASTNET hourly ozone data from Denali, using 40 ppb default for missing hours (unchanged from initial exemption study and this is the correct setting).
  - A background ammonia concentration of 0.5 ppb (unchanged from initial exemption study and this is the correct setting).
  - Regulatory default model options when such options are specified (unchanged from initial exemption study and this is the correct setting).
  - National Park Service discrete receptor locations and elevations for Denali National Park and the Tuxedni Wilderness (http://www2.nature.nps.gov/air/maps/Receptors/index.cfm) (unchanged from initial exemption study and this is the correct setting).

- Aerodynamic building downwash was not used in the modeling analysis (ML&P indicated in their protocol document that such would be reflected in the modeling, but the Department commented that modeling the effects of downwash was not required and such was not used in the study) (unchanged from initial exemption study and this is the correct setting).
- CALPUFF computational grid for Denali visibility modeling consistent with the Geomatrix meteorological domain (NX=270, NY=325); and an acceptable reduced computational grid used for Tuxedni visibility modeling (NX=200, NY=200) (unchanged from initial exemption study and this is the correct setting).

- CALPOST modeling files:
  - In the initial exemption study, ML&P incorrectly selected the FLAG (2000) f(RH) hygroscopic species particle growth curve option instead of the EPA (2003) option, i.e., MFRH=2 instead of 3. Irrespective of this, the August Findings Report also indicated that the correct EPA (2003) monthly f(RH) background values where applied to MVISBK=6 for each of the two Class I areas, as taken from Table A-2 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003). ML&P has applied the correct option (i.e., MFRH=3) in the revised modeling analysis along with the correct monthly f(RH) background values.
  - PM coarse (PMC) and PM fine (PMF) have been included in computing light extinction for the source; however, since only total PM2.5 has been modeled in CALPUFF (i.e., no speciation of source coarse and fine fractions), ML&P conservatively equated each of PMC and PMF to PM2.5 when computing light extinction for the source (unchanged from initial exemption study and this is conservative and acceptable).
  - Except for modeled PM fine (PMF) discussed below, CALPOST default extinction efficiencies were used for PM coarse (PMC), ammonium sulfate, ammonium nitrate, organic carbon (OC), and elemental carbon (EC) (unchanged from initial exemption study and this is the correct setting).
  - As discussed previously, the August Findings Report to the initial study noted that an extinction efficiency of 10.0 m^2/g was applied to PMF concentrations instead of the default PMF efficiency value of 1.0 m^2/g. It was further noted that the use of 10.0 m^2/g versus 1.0 m^2/g would be expected to produce higher predicted visible impacts for the source, thereby increasing the change to extinction (delta deciviews) predicted by CALPOST. ML&P has continued to apply this conservative extinction efficiency value in the revised exemption study.
  - In both the initial and revised analyses, the background extinction and change to extinction calculations were made using the recommended CALPOST Method 6 (MVISBK=6). Monthly relative humidity adjustment factors specific to each Class I area have been taken from Table A-3 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003). Although ML&P used Table A-2 in the initial exemption study, use of Table A-3 is acceptable since there is no material difference between Tables A-2 and A-3 (as noted in the August Findings Report); EPA makes no distinction or recommendation on which

table to apply in BART modeling applications; and Table A-3 is consistent with the WRAP-RMC modeling study.

- The August Findings Report indicated that the Class I area monthly background aerosol concentrations were not reflective of the annual average natural background concentrations used by WRAP, as recommended at Table 2-1 of the EPA 2003 guidance document. The correct annual average natural background concentrations (i.e., Table 2-1, EPA 2003) have been utilized by ML&P in the revised exemption study.

<u>IMPROVE Equation and Federal Land Manager (FLM) Comments</u>
ML&P indicated in their December 31, 2007 protocol clarification that they would use both the "old" and "new" IMPROVE equations in the BART exemption analysis. ML&P's revised exemption analysis therefore includes the results from both equations. While the Department accepted this dual approach during protocol review, they subsequently asked Enviroplan to *focus* their review on ML&P's use of the "old" IMPROVE equation. This is the equation being used by all but one of the other Alaska BART eligible sources and the equation used by WRAP-RMC. Therefore, the "old" equation provides the most consistency between BART sources. Per ML&P's findings, it also provided the largest visibility impacts.

Visible impact results associated with the application of the "old" equation are reflected in the output from CALPOST (i.e., Method 6 (MVISBK=6)). The "old" equation CALPOST results are summarized in the ML&P revised exemption study report.

While not a major focus of the review, Enviroplan is nevertheless providing the following comments regarding ML&P's use of the "new" IMPROVE equation. Visible impacts associated with the "new" equation, which are reflective of the 2005 recommendations made by the IMPROVE Steering Committee ("Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data", IMPROVE technical subcommittee for algorithm review, January 2006), must be computed external to CALPOST version 5.6394. A methodology has been developed by Dr. Ivar Tombach ("Instructions: A Postprocessor for Recalculating CALPOST Visibility Outputs with the New IMPROVE Algorithm - Version 2", October, 14 2006) to compute visible impacts using the new IMPROVE equation. This methodology is in the form of a Microsoft Excel spreadsheet which requires CALPOST output summary data to be input by the user. The spreadsheet also contains default relative humidity factors f(RH) utilized in the worksheet's imbedded calculations. The user is prompted for a site-specific Rayleigh scattering coefficient, and can optionally enter information on Class I area sea salt concentrations and CALPUFF predicted 24-hour NOx concentrations. ML&P utilized the new IMPROVE spreadsheets without the optional 24-hour NOx concentrations, and the results are summarized in their study report.

On September 3, 2008, the U.S. Fish and Wildlife Service (FWS) provided the Department with comments on the ML&P revised exemption analysis. The comments included an indication that the monthly natural background relative humidity factors, f(RH), were incorrect and should reflect the 2003 EPA guidance. It has been determined during this review that ML&P did correctly apply the 2003 EPA recommended f(RH) values in their revised exemption analysis.

The FWS also commented that ML&P should include predicted impacts of 24-hour NOx when using the new IMPROVE worksheets. Since instructions on use of the worksheet indicate such information is optional, ML&P did not apply 24-hour NOx concentrations. For informational purposes only, a cursory sensitivity analysis was performed using a maximum 24-hour NOx concentration of 0.2 ppmv reported by ML&P as input to the new IMPROVE worksheets. Assuming 100% conversion of NOx to NO2, Enviroplan determined that the 24-hour NOx concentrations had no effect on the conclusions to the revised study. It is noted, however, that the sea salt concentration and Rayleigh scattering coefficient used by ML&P in the Denali worksheets mistakenly reflected the respective values for Tuxedni. A summary of the cursory sensitivity analysis results comparing new IMPROVE visibility predictions made by ML&P without 24-hour NOx concentrations to visibility predictions made using 24-hour NOx concentrations, and correcting for Denali sea salt and Rayleigh scattering values, are shown below for informational purposes.

Anchorage ML&P - 98th Percentile Delta Deciview Values			
2002	**2003**	**2004**	**Significance Threshold**
New IMPROVE - ML&P Predictions Without 24hr NOx			
Denali			
0.34	0.38	0.25	0.5
Tuxedni			
0.23	0.24	0.16	0.5
New IMPROVE Sensitivity Analysis - ML&P Predictions With 24hr NOx			
Denali			
0.37	0.42	0.29	0.5
Tuxedni			
0.26	0.27	0.19	0.5

BART exemption analysis results

Results of the visible impacts modeling have been summarized by ML&P in Table 2 of their revised August 25, 2008 report. The "significance" metric against which these values are compared is a 0.5 deciview change. These tabulated results demonstrate compliance with the 0.5 deciview change metric for both Class I areas and all three years of meteorological data.

Findings Review Conclusions

A detailed review of the revised ML&P BART-eligible exemption analysis has been conducted. It has been determined that data and procedures utilized by ML&P in the revised modeling analysis are consistent with the approved modeling protocol; and the recommendations provided in the Findings Report of August 6, 2008. Overall, Anchorage ML&P has successfully demonstrated the visibility analysis conducted for their BART eligible sources meets federal and state provisions on exempting these units from otherwise applicable BART control requirements.

ENVIROPLAN CONSULTING

Findings Report
Agrium Kenai Nitrogen Operations (Agrium)
Best Available Retrofit Technology (BART) Evaluation

Prepared for

State of Alaska
Department of Environmental Conservation
Division of Air Quality

ADEC Contract No. 18-3001-17
NTP No. 18-3001-17-7A

Prepared by
Enviroplan Consulting
Edgewater Commons II
81 Two Bridges Road
Fairfield, NJ 07004

Enviroplan Consulting Project No. 209916.15
November 25, 2008

EXECUTIVE SUMMARY

Enviroplan Consulting (Enviroplan) was retained by the Alaska Department of Environmental Conservation (Department) to review a Best Available Retrofit Technology (BART) control analysis submitted on July 28, 2008 by Agrium Kenai Nitrogen Operations (Agrium), with supplemental information submitted on October 9 and 17, 2008. The Department previously approved, on April 18, 2008, the related visibility modeling protocol submitted by Agrium on January 29, 2008. The BART control analysis was prepared by Agrium pursuant to the Federal Regional Haze Rule, 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule*; and the Department's regulation relating to BART, 18 AAC 50.260. The Department has not exempted Agrium from the requirements of BART; therefore, pursuant to 18 AAC 50.260(b), Agrium must comply with, paragraphs (d) through (h) and (l) through (o) of 18 AAC 50.260.

The purpose of this report is to document Enviroplan's findings regarding Agrium's BART control analysis in terms of compliance with 18 AAC 50.260(e) through (h). This report also proposes a preliminary BART determination for each BART-eligible source at this facility, pursuant to 18 AAC 50.260(j). Important in the review of the control analysis and preliminary BART determinations is the fact that the facility is not operating due to an unavailability of natural gas, which is a primary feedstock used for production at the site. Production at the plant has been discontinued since 2006, and it is unknown when the facility will initiate production in the future. Agrium completed the requisite BART control analysis by making *general assumptions* regarding the cost and adequacy of the various retrofit control options. However, Agrium was unable to perform a detailed engineering analysis of the retrofit control options since it is unknown how the affected equipment would be operated when and if the plant reopens.

Enviroplan discussed Agrium's unique situation with the Department. The Department instructed Enviroplan to make a *conditional* preliminary BART recommendation, under the premise that Agrium would need to submit a *revised* and detailed BART control analysis prior to restarting the plant. The Department intends to incorporate the requirement to revise the BART analysis into Agrium's Title V operating permit.

Based on the above understanding, the Agrium BART control analysis complies with 18 AAC 50.260(e) through (h); and the control options proposed by Agrium are *conditionally accepted* as preliminary BART pursuant to 18 AAC 50.260(j). For each combustion related BART eligible source (i.e., 5 package boilers, five turbine/gensets, two primary reformer and two CO2 compressor engines), use of natural gas fuel and good combustion practices is preliminary BART; and for the Urea Prill Tower, Granulators A/B and materials handling at the Urea Loading Wharf, good management and operating practices is preliminary BART.

The following sections of this document provide the detailed findings associated with Agrium's July 2008 BART control analysis and the resultant preliminary BART determinations. As indicated above, the control analysis is consistent with 18 AAC 50.260(e) through (h).

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1 INTRODUCTION

On July 6, 2005, the U.S. Environmental Protection Agency (EPA) published the final "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations" (the "Regional Haze Rule" 70 FR 39104). The rule is codified at 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y. The Regional Haze Rule requires certain States, including Alaska, to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I Areas. The Regional Haze Rule requires states to submit a plan to implement the regional haze requirements (the Regional Haze SIP). The Regional Haze SIP must provide for a Best Available Retrofit Technology (BART) analysis of any existing stationary BART-eligible source that might cause or contribute to impairment of visibility in a Class I Area. BART-eligible sources include those sources that:

1. have the potential to emit 250 tons or more of a visibility-impairing air pollutant;
2. were in existence on August 7, 1977 but not in operation prior to August 7, 1962; and
3. whose operations fall within one or more of the specifically listed source categories in 40 CFR 51.301.

During 2007 the Department developed a list of Alaska BART-eligible sources based on the federal BART guidelines. Agrium's ammonia and urea production facility in Kenai, Alaska has been identified by the Department as required to conduct BART assessments for its BART-eligible emission units. The BART-eligible emission units at this plant are shown at the end of this section in Table 1-1. The requirements applicable to Alaska BART-eligible sources were published by the Department on December 30, 2007 under 18 ACC 50.260. The Department's BART regulation requires sources not exempt from applicability based on a visibility modeling analysis to submit a case-by-case BART proposal for each BART-eligible unit at the facility and for each visibility impairing pollutant (VIP) by July 28, 2008.

During 2007 a preliminary regional BART screening modeling analysis was conducted that included all BART-eligible sources in Alaska. The modeling was completed by the Western Regional Air Partnership (WRAP) - Regional Modeling Center (RMC). The simulations were done using the CALPUFF modeling system and a single year, 2002, of processed MM5 CALMET data. The simulations were performed to evaluate predicted impacts of visibility in two Alaska PSD Class I areas, the Tuxedni National Wildlife Refuge designated as a National Wilderness Area (Tuxedni) and the Denali National Park including the Denali Wilderness but excluding Denali National Preserve (Denali). BART-eligible sources are exempt from BART if the daily visible impacts at a Class I area are below screening criteria set by ADEC, EPA, and the Federal Land Managers (FLMs). Pursuant to 18 AAC 50.260(q)(4), a 0.5 or greater daily deciview change when compared against natural conditions is considered to "cause" visibility impairment.

The initial modeling analysis conducted by WRAP - RMC indicated that the maximum visibility impact of Agrium's facility at both the Tuxedni and Denali Class I areas were higher than the 0.5 delta-deciview visibility screening threshold. The Department notified Agrium in December 2007 that they were subject to the BART control analysis requirements for the affected equipment since the WRAP – RMC analysis was unsuccessful at providing a basis for exemption.

In anticipation of the Department's notification Agrium and other Alaska BART sources (also known as "the BART Coalition") refined and expanded the MM5 meteorological data set used by WRAP - RMC and developed a revised MM5 data set for subsequent BART modeling purpose. The revised MM5 data set, which were approved by the Department on November 30, 2007, consists of a 5-kilometer, 3-year data set and is a major improvement from the 15-kilometer, 1-year MM5 data set used by WRAP. The BART Coalition also submitted a revised CALMET modeling protocol for processing the meteorological data. The Department approved the revised CALMET modeling protocol on December 19, 2007.

Agrium submitted a CALPUFF protocol on January 29, 2008 and provided revised information, in response to Department comments, on March 11, 2008. The Department approved Agrium's revised protocol on April 18, 2008. The subsequent CALPUFF analysis conducted by Agrium was used to support the control analysis submitted on July 28, 2008.

The following sections of this report present the review findings pertaining to both the Agrium control analysis and the related CALPUFF modeling files. Enviroplan performed the review to determine whether Agrium's analysis conforms to the above specified protocol documents and the related rules and regulatory guidance, including 18 AAC 50.260(e) - (h), *Guidelines for best available retrofit technology under the regional haze rule;* 40 CFR 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule,* and U.S. EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA-454/B-03-005, September 2003). The review also includes recommended preliminary BART determinations for each BART-eligible source at this facility, pursuant to 18 AAC 50.260(j).

Pursuant to 40 CFR 51, Appendix A, BART engineering analysis requires the use of six statutory factors for any BART-eligible source that is found to cause or contribute to atmospheric visibility impairment in any of 156 federal parks and wilderness areas protected under the regional haze rule (i.e., mandatory Class I areas). These factors include: 1) the available retrofit options, 2) any pollution control equipment in use at the source (which affects the availability of options and their impacts), 3) the costs of compliance with control options, 4) the remaining useful life of the facility, 5) the energy and non-air quality environmental impacts of control options, and 6) the visibility impacts analysis.

Agrium has conducted the BART control analysis utilizing the above referenced factors. Agrium has concluded that the BART-eligible sources at the Kenai facility do not require additional retrofit controls because the potentially feasible control options are either not cost effective, the control options do not result in significant visibility benefit, and/or the cost of visibility improvement resulting from potentially installing these control options are highly cost prohibitive. Agrium considers the existing controls and operating practices on BART-eligible sources at the facility as BART.

Given that the Agrium facility has not operated since 2006 due to an unavailability of natural gas, which is a primary feedstock used for production at the site; and since it is unknown when the facility will initiate production in the future; the Department has decided to conditionally accept Agrium's BART determinations due to the non-operational status of the plant and Agrium's resultant inability to conduct detailed site-specific engineering analyses of potential retrofit control options. The remainder of this findings report summarizes Agrium's BART control analysis and resultant determinations. Enviroplan reviewed Agrium's control analysis to ensure compliance with 18 AAC 50.260(e) - (h), i.e., the six (6) statutory factors cited above as contained at 40 CFR 51, Appendix A. Details on the findings of this review are contained in Appendix A to this report. Should Agrium decide in the future to re-commence operations at the Kenai facility, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

Table 1-1: List of BART eligible sources at Agrium Kenai Nitrogen Operations Plant

Source ID	Source Description	Rated Capacity	Baseline Actual Emissions (tpy)		
			NO_x	SO_2	PM
2	Primary Reformer	1,450 MMBtu/hr	717	1	41
12	Primary Reformer	1,350 MMBtu/hr	1,285	0.78	42.8
24/25	CO_2 Compressor	5.2 MMBtu/hr	39.4	0.15	0.98
27	Urea Prill Tower	65 tons per hour (product)	-	-	361.3
35/36	Granulators A/B	N/A	-	-	8.7
42	Package Boiler	156 MMBtu/hr	30.3	0.7	1.3
43	Package Boiler	156 MMBtu/hr	25.6	1.7	3.1
44	Package Boiler	183 MMBtu/hr	27.4	1.8	3.3
48	Package Boiler	230 MMBtu/hr	93	0.3	4.3
49	Package Boiler	230 MMBtu/hr	95.5	0.3	4.5
55-59	Turbine/Gen Set	37.5 MMBtu/hr	76.2	0.1	1.1
47	Urea Loading Wharf	Fugitive Dust Source	-	-	

Notes:
1. Actual baseline emissions are based on data for the year 2002, which is considered by Agrium as representative of future operations.

2 ELEMENTS OF THE BEST AVAILABLE RETROFIT TECHNOLOGY ANALYSIS

On July 1, 1999 (40 CFR Part 51), EPA published the Regional Haze Rule which provides the regulations to improve visibility in 156 national parks, wilderness areas, and international parks which were in existence in 1977. One of the key elements of the Regional Haze rule addresses the installation of BART for certain source categories that were built and in operation between 1962 and 1977. BART is defined as:

> "an emissions limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emissions limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

BART, also referred to as the "Clean Air Visibility Rule" (CAVR), requires states to identify "BART-eligible" sources. Sources need to meet all three criteria to be considered "BART-eligible" including:

1. The source belongs to one of the 26 listed source categories; these categories are same as those for Prevention of Significant Deterioration (PSD) applicability analysis;
2. The source was installed (constructed) and in operation between 1962 and 1977; and
3. The source emits more than 250 tons per year of any one or all of the visibility impairing pollutants including sulfur dioxide (SO_2), nitrogen oxide (NO_2), or particulate matter (PM_{10}). Volatile organic compounds (VOC) and ammonia (NH_3) may be included depending on the state in which the source is located.

The Alaska BART rule (18 AAC 50.260(f)) requires BART analysis to be conducted for NO_x, SO_2, and PM_{10} only (i.e., visibility impairing pollutants). The BART analysis identifies the best system of continuous emission reduction taking into account:

1. The available retrofit control options,
2. Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
3. The costs of compliance with control options
4. The remaining useful life of the facility,
5. The energy and non-air quality environmental impacts of control options, and
6. The visibility impacts analysis.

The five basic steps of Case-by-Case BART Analysis are:

STEP 1—Identify All Available Retrofit Control Technologies,

In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.

STEP 2—Eliminate Technically Infeasible Options,

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

Agrium calculated the cost effectiveness of the evaluated control technologies. The average cost effectiveness in dollar per ton removed is determined using the following formula:

Control option annualized cost / (baseline annual emissions – annual emissions with control options)

The control technology costs used in this analysis are primarily based on EPA's cost control manual and the cost estimates which represent 1990 dollar amounts. Costs were escalated to reflect 2008 dollar amounts by using the Chemical Engineering Plant Cost Index (CEPCI). For cyclones, costing information comes from EPA's Air Pollution Control Fact Sheet on cyclones.

STEP 4—Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

Sections 2.1 through 2.3 presented below provide a summary of the retrofit control options deemed by Agrium as potentially feasible for the BART-eligible sources at the plant. The control options are presented for each VIP: NO_x, SO_2 and PM_{10}. Following the listing of feasible control options, the specific options considered by Agrium for each BART-eligible source at the plant are summarized in Sections 2.4 through 2.8. Information presented in Sections 2.4 through 2.8 includes related cost and energy and non-air quality environmental impacts of control options, and the visibility impacts analysis. The final BART determinations suggested by Agrium are also presented in these sections. As indicated earlier in this document, the specified determinations will be considered as BART for purposes of this study.

Agrium's evaluation of each of the steps described above complies with 18 AAC 50.260(e) - (h). Since the plant is non-operational and no site-specific engineering analyses have been conducted, Agrium has considered the technologies specified below as feasible for the purposes of this evaluation. Should Agrium decide in the future to restart production at this plant, the technological and economic viability of these options, and any other potentially feasible technologies available at the time of plant restart, will need to be fully evaluated. Agrium would then need to submit the revised detailed evaluation for approval prior to restarting the plant.

2.1 NO_X CONTROL TECHNOLOGIES CONSIDERED

The following provides a listing of the NO_x retrofit control technologies considered by Agrium for the Kenai plant BART-eligible combustion sources. Any retrofit option deemed by Agrium as potentially infeasible is identified as such.

Water/Steam Injection

Steam or water injection is used to reduce the flame temperature, thereby reducing the formation of thermal NO_x. Water/steam injection is not effective in reducing fuel NO_x formation. Another version of this technique is to inject a water-in-oil emulsion, which operates on a similar principle as water/steam injection to reduce NO_x. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to its injection. The water emulsified in fuel oil reduces the flame temperature in the combustion zone thereby reducing thermal NO_x; however, water-in-oil emulsion is not effective in reducing fuel generated NO_x.

Flue Gas Recirculation (FGR)

Flue gas recirculation involves recycling a portion of the combustion gas to the boiler. The low oxygen combustion product, when mixed with combustion air, reduces the excess combustion air; thereby, reducing the peak flame temperature and thermal NO_x formation. However, there is insignificant effect on fuel NO_x. As a result, FGR is more effective with low nitrogen content fuels such as natural gas and distillate fuel oil rather than residual fuel oil. FGR is normally applied in combination with new low-NO_x burners because the performance of many burners is adversely affected with the introduction of new inert gases in the combustion zone.

Staged Combustion Air (SCA)

Staged combustion involves injecting a portion of the combustion air downstream of the fuel-rich primary combustion zone. This can be achieved by using secondary over-fire air (OFA), side-fired air ports, or the burner out of service (BOOS) technique. SCA is not considered a viable option for retrofit to package boiler units due to installation difficulties.

Combustion Control

Combustion controls reduce NO_x emissions by controlling the combustion temperature or the availability of oxygen. These are referred to as “low NO_x burners” or “ultra low NO_x burner.” There are several designs of low/ultra low NO_x burners (ULNB) currently available. These burners combine two NO_x reduction steps into one burner, typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without requiring external equipment.

In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. This design is predominately used with liquid fuels.

In staged fuel burners with IFGR, fuel pressure induces the IFGR, which creates a fuel lean zone and a reduction in oxygen partial pressure. This design is predominately used for gas fuel applications.

Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) is a post-combustion NO_x control technology based on the reaction of NH_3 and NOx. SNCR involves injecting urea/NH_3 into the combustion gas path to reduce the NOx to nitrogen and water. This reaction is described by the following chemical equation:

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

The optimum exhaust gas temperature range for implementation of SNCR is 1,200°F to 2,000°F. Operation at temperatures below this range results in NH_3 slip, while operation above this temperature range results in oxidation of NH_3, forming additional NO_x. In addition, the urea/ammonia must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO_x reduction. The exhaust temperatures of the process heaters range from 350°F to 700°F, and temperatures ranging from 1,200°F to 2,000°F are required to prevent significant ammonia slip. Based on a review of the EPA's RBLC database (see summary in Appendix B) for the last five years, no industrial boilers were controlled by SNCR; therefore, SNCR is not considered a technically feasible control option of the boilers at the facility.

Selective Catalytic Reduction (SCR)

SCR is a process that involves post combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, ammonia slip emissions, and design of the NH_3 injection system.

Reduction catalysts are divided into two groups: platinum and base metal (primarily vanadium or titanium). Both groups exhibit advantages and disadvantages in terms of operating temperature, reducing agent/NO_x ratio, and optimum oxygen concentration. A disadvantage common to both platinum and base metal catalysts is the narrow range of temperatures in which the reactions will proceed. Platinum group catalysts have the advantage of requiring lower ignition temperature, but also have a lower maximum operating temperature. Operating above the maximum temperature results in oxidation of NH_3 to either nitrogen oxides (thereby actually increasing NO_x emissions) or ammonium nitrate.

Sulfur content of the fuel can be a concern for systems that employ SCR. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in gas and the mercaptans used as an odorant) to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. Sulfur trioxide and sulfuric acid reacts with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled or may be emitted from the stack as increased emissions of PM_{10}/ $PM_{2.5}$. Fouling can eventually lead to increased system pressure drop over time and decreased heat transfer efficiencies.

The SCR process is also subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result of either prolonged exposure to excessive temperatures, or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically only guarantee a 3-year lifetime to achieve low emission levels for high performance catalyst systems.

SCR manufacturers typically estimate 10 to 20 ppm of unreacted ammonia emissions (ammonia slip) when making guarantees at very high efficiency levels. To achieve high NO_x reduction rates, SCR vendors suggest a higher ammonia injection rate than stoichiometrically required, which results in ammonia slip. Ammonia slip may increase atmospheric PM formation, which is a visibility impairing pollutant. Thus, an emissions trade off between NO_x and ammonia occurs in high NO_x reduction applications. While SCR may be considered potentially technically feasible for the boilers, there are various concerns with the technology, most notably the temperature required for the catalyst to activate and the unreacted ammonia introduced into the exhaust stream.

Ultra Low NO_x Burners and FGR

This is most commonly used NO_x control technique for fuel oil-fired boilers. Also, it is more often feasible for installing FGR along with ULNB, rather than FGR alone.

Ultra Low-NO_x Burners and SNCR

This method uses a combination of combustion control and SNCR. Available information indicates that SNCR is not currently used in combination with combustion controls on boilers. Additionally, there is no data to indicate that SNCR could achieve the same percent reduction when starting from the low NO_x inlet level of a process heater with combustion controls as compared to uncontrolled levels.

Ultra Low-NO_x Burners and SCR

This method uses a combination of combustion control and SCR. When SCR is used in combination with combustion controls, the inlet NO_x level to the SCR control device is lower than from an uncontrolled source. The SCR system may not achieve the same percent reduction when starting from the low NO_x inlet level of a heater with combustion controls as compared to uncontrolled levels.

2.2 SO_2 CONTROL TECHNOLOGIES CONSIDERED

The following provides a listing of the retrofit technologies deemed by Agrium as potentially feasible for SO_2 emitting BART-eligible sources at the Agrium Kenai plant, which are combustion type emission units.

Fuel Switching

Limiting the sulfur content of the fuel will limit the amount of SO_2 emissions from the process heaters. More SO_2 emissions are emitted from solid fuels (e.g. coal) and fuel oil (#6 Oil).

Wet Scrubbing

Wet gas scrubbers chemically remove SO_2 emissions by absorption neutralization and partial oxidation to calcium sulfate using aqueous solutions. The absorption of SO_2 with caustic is the simplest method of flue gas desulfurization. In this scrubbing system, the flue gas and a caustic solution flow counter-current to each other. A dual alkali scrubber system utilizes a solution of sodium sulfite (Na_2O_3S) and sodium hydroxide (NaOH) to provide absorption and neutralization of SO_2 within the spray tower. The sulfur reacts with the caustic solution and is stripped out of the flue gas stream. Since both sodium sulfite and sodium hydroxide are soluble in water, no precipitation occurs within the scrubber. However, water contamination issues arise with the disposal of large volumes of sodium sulfite and sodium sulfate solution. Lime or limestone is added to the scrubber effluent along with additional sodium hydroxide or soda ash to precipitate the sulfite/sulfate ions and regenerate the sodium hydroxide.

2.3 PM CONTROL TECHNOLOGIES CONSIDERED

The following provides a listing of the retrofit technologies deemed by Agrium as potentially feasible for PM_{10} emitting BART-eligible sources at the Agrium Kenai plant. Such sources include combustion type emission units; materials handling fugitive emissions generating activities at the Urea Loading Wharf; and process units including Granulators A/B and the Urea Prill Tower.

Good Combustion Practice

By maintaining the boilers in good working order per manufacturer's specifications, emissions of PM_{10} can be limited.

Wet Scrubbing

A wet scrubber uses gas/liquid contact to remove particles by inertial impaction and/or condensation of liquid droplets on particles in gas stream, in a similar fashion to that already described for SO_2 emissions.

Cyclone

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals toward the bottom of the cyclone. As the particles, in a spinning motion, proceed downward the heavier material hits the outside wall and drops to the bottom and is collected. The cleaned gas escapes through an inner tube.

Dry/Wet Electrostatic Precipitation

Electrostatic Precipitators (ESPs) involve a high voltage electrode and a grounded electrode. As the flue gas passes between the electrodes, particles become charged and are collected at the grounded electrode. These particulates are removed either by vibration ("dry" ESPs) or by washing ("wet" ESPs).

Wet Scrubber with Mist Eliminator

In a wet gas scrubber, the air flow from the process is passed through a stream of water, where the particulates are captured. The primary mechanism used is impaction, followed by absorption, interception, and diffusion. The types of available scrubbers include a spray tower, tray tower, dynamic scrubber, venturi scrubber, and orifice scrubbers. The scrubbers differ in the mechanism used to capture particles including flow rates, and direction of air and water flows. Wet gas scrubbers may be effective for PM control from the prilling and granulation process because they work well with particles which are in wet form and are hygroscopic in nature. Scrubbers have been used for industrial application including boilers, asphalt production, and fertilizer plants. The collection efficiency of the scrubber depends on the particle size and the efficiency decreases with decreasing particle size. In some cases, venturi scrubbers are equipped with mist eliminators, which help reduce the formation of particles and serve as additional control for PM. The droplets which remain entrained in the air after it passes through the scrubber, pass through a chamber with baffles/cyclones, which may help remove PM from the waste stream using impaction. As discussed earlier, one of the problems with wet scrubbers is the generation of a liquid waste stream which needs to be treated. This is a concern at the Agrium facility in Kenai, given the limited wastewater treatment operations on site, and the fact that there would be a direct discharge of effluent high in nitrogen content to Cook Inlet.

Wet ESP

As discussed earlier, in an electrostatic precipitator, PM emissions are controlled by charging the particles and passing them through a charged electric plate. A wet ESP is normally used when the air flow from the source is saturated with moisture. The water may be supplied either intermittently or continuously. One concern with a wet ESP is the introduction of a contaminated effluent high in nitrogen content which must be disposed of.

Water/Chemical Suppressants

The use of water/chemical suppressants is more common for controlling fugitive dust emissions from unpaved roads. In this control option, water or chemicals are sprayed on the ground to settle the dust particles and reduce the particles from being entrained in the air. Chemicals that are generally used as suppressants include fiber-based dust palliatives, calcium chloride, magnesium chloride, petroleum resin, polymer, etc. The control efficiency depends on the duration between applications, meteorological conditions, application rate, and dilution rate (for chemical application). Control efficiencies of up to and above 80% have been achieved with the use of this control option.

Fabric Filtration/Baghouse

Fabric filtration removes particles from a gas stream with a baghouse. An air stream flows through a number of parallel filter bags, where particulate collects on the fabric. Baghouses are commonly used for industrial applications.

Fuel Switching

Similar to SO_2 emissions, the emissions of PM can be reduced by switching from fuel oil to natural gas. In addition, reducing the sulfur content of the fuel results in lower PM emissions.

2.4 BART DETERMINATION - PACKAGE BOILERS (EU 42, 43, 44, 48, and 49)

This section of the BART analysis identifies and describes the potentially available retrofit control technologies for package boilers (Sources 42, 43, 44, 48, and 49) at the facility. Related summary information on retrofit option costs, and energy and non-air quality environmental impacts of control options and the visibility impacts analysis is also presented. The final BART determinations suggested by Agrium are also presented in these sections. As indicated earlier in this document, the specified determinations will be considered as BART for purposes of this study.

Available Controls for NO_x - Package Boilers

The principal mechanism of NO_x formation in gas combustion is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in the high temperature flame zone near the burners. Emission levels vary considerably with the type and size of burner design, and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The following is a list of control technologies identified by Agrium which are potentially capable of controlling NO_x emissions from boilers.

- Water/Steam Injection;
- Flue Gas Recirculation (FGR);
- Combustion Control (including Low NO_x and Ultra Low-NO_x burners);
- Selective Non-Catalytic Reduction (SNCR);
- Selective Catalytic Reduction (SCR);
- Ultra Low NO_x Burners and Flue Gas Recirculation (FGR);
- Ultra Low- NO_x Burners and SNCR; and
- Ultra Low- NO_x Burners and SCR.

In their report, Agrium stated that each of the control methods identified above are considered technically feasible for controlling NO_x emissions from the facility BART-eligible boilers, with the exception of water/steam injection, SNCR and ULNB+SCNR. Water/steam injection is predominantly employed on gas turbines, and it was found not to be technically feasible for the boilers due to operating issues concerning flame stability during water/steam injection. The exhaust temperature from the boilers is too low to render SNCR feasible; and no referenced use of ULNB +SCNR technology in commercial applications was identified by Agrium in their control technology literature search.

In addition to the above, Agrium did not further analyze flue gas recirculation, staged combustion air, and the combination of ultra-low NO_x burners with selective catalytic reduction or ultra-low NO_x burners with flue gas recirculation. Reasons cited were that the plant was not operational and the significantly higher cost of combined controls without proportionate increase in control efficiently compared to separate controls.

Estimated control efficiencies for viable retrofit control options are presented in Table 2-1 below.

Table 2-1- Control Effectiveness of the NO_x Control Options

Control Technology	***Estimated Control Efficiency (%)****
LNB	30-70
UNLB	55-80
SCR	70-90
Fuel Switching	65

*Data for control efficiencies obtained from Alternative Control Techniques Document - NOx Emissions from ICI Boilers, Alternate Control Techniques Document - NOx Emissions from Stationary Gas Turbines, Alternate Control Techniques Document - NOx Emissions from Process Heaters and Air Pollution Control Fact Sheet (EPA-452/F-03-032).

For Agrium's analysis, the cost of NO_x controls is evaluated for three control options ~ low NO_x burners (LNB), ULNB, and selective catalytic reduction (SCR) systems. These controls are chosen because they represent the anticipated range of NO_x controls based on the following factors:

- most common/widely used,
- cost of controls, and
- achievable level of control (i.e., control efficiency).

Of the three options, LNB represents the lower end of control efficiency, ULNB the middle of the range, and SCR represents the high end of emissions reduction. It should be noted that the analysis did not include detailed engineering review of the cost associated with retrofitting the equipment. The following table summarizes the cost effectiveness of the analyzed options:

Table 2-2 - Summary of Cost-Effectiveness for NO_x Controls on Package Boilers

Source ID	Source Description	Cost Effectiveness ($/ton)		
		LNB	ULNB	SCR
042	Package Boiler	34,700	13,900	8,800
043	Package Boiler	41,000	16,450	10,350
044	Package Boiler	49,500	17,300	11,100
048	Package Boiler	21,000	6,500	4,100
049	Package Boiler	20,500	6,300	4,000

The costs of these control options are considered above an economically reasonable range, especially given the uncertainties in retrofitting these technologies on the existing units. There are concerns regarding impacts to the operating capacity of the equipment (i.e., energy penalty). In particular for SCR systems, potential environmental impacts from the use of ammonia in the SCR system and subsequent concerns are summarized below:

- Unreacted ammonia would be emitted to the atmosphere (ammonia slip); ammonia is a PM_{10} (and $PM_{2.5}$) precursor;
- Small amounts of ammonium would also combine with NO_x and SO_2 to form ammonia salts, which would be emitted to the atmosphere as PM_{10}; and
- There are significant safety issues associated with the transportation, handling, and storage of aqueous and anhydrous ammonia.

Therefore, Agrium found that the costs to install add-on controls for each of the package boilers are not considered to be cost effective. BART for these sources for NO_x is the continued use of good combustion practices and firing of predominantly natural gas fuel.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A

Available Controls for SO_2 - Package Boilers

SO_2 emissions are directly related to the amount of sulfur in the fuel. Nearly all sulfur in the fuel is converted to SO_2 during the combustion process. The only available SO_2 control technology for the package boilers is Wet Scrubbing and it was deemed technically feasible. For natural gas-fired boilers, installing an additional retrofit control, such as a wet scrubber is not expected to result in significant further emission reductions, since SO_2 emissions are already very low (i.e., < 3 tons per year per source). However, a cost analysis for installation of wet scrubbing technology was conducted for the boilers with the results summarized in Table 2-3 below:

Table 2-3 - Summary of Cost Effectiveness for Add-On SO_2 Controls on Package Boilers

Source ID	Source Description	Control Efficiency	Cost Effectiveness of Wet Scrubber ($/ton)
042, 043	Package Boiler	90%	285,000
044	Package Boiler	90%	391,000
048, 049	Package Boiler	90%	2,000,000

Notes:
The cost effectiveness evaluation for boilers with similar characteristics (i.e., flow rates, emissions) was combined in this analysis.

Due to the high cost effectiveness values presented in Table 2-3, the installation of wet gas scrubbers on the package boilers is not considered reasonable. In addition to the excessively high cost per ton values for the wet scrubbers, the visibility benefits which may be recognized if such controls were installed are considered statistically insignificant. Therefore, no additional controls are proposed for the package boilers to reduce SO_2 emissions. The use of good combustion practices and firing of predominantly natural gas are considered BART for these sources.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

Available Controls for PM_{10} - Package Boilers

PM_{10} emissions are generally related to the combustion process and fuel type. Firing gaseous fuel has inherently lower PM_{10} emissions than liquid fuels, which in turn have lower emissions than solid fuels.

The following is a list of potentially available control technologies for controlling PM_{10} emissions from the boilers:

- Good Combustion Practice;
- Wet Scrubbing;
- Cyclone;
- Dry/wet electrostatic precipitation;
- Fabric Filtration/baghouse; and
- Fuel Switching.

All of the above control options were considered potentially technically feasible for reducing PM emissions from the package boilers, pending a detailed engineering evaluation of technical feasibility.

For this evaluation, cost estimates were conducted for the wet scrubber, ESP, and baghouse technologies, based on the expectation that these technologies would form a lower and upper bound estimate of the potentially available technologies. Each of these technologies was assumed to provide for up to a 95% reduction in PM emissions.

The costs associated with retrofitting add-on controls on the package boilers is summarized in Table 2-4 below.

Table 2-4 - Summary of Cost Effectiveness for Add-On SO_2 Controls on Package Boilers

Source ID	Source Description	Cost Effectiveness ($/ton)			
		Cyclone	**Baghouse**	**ESP**	**Wet Scrubber**
042, 043	Package Boiler	20,910	39,000	17,900	30,600
044	Package Boiler	20,910	80,500	17,900	58,700
048, 049	Package Boiler	20,910	39,100	15,800	26,200

Notes:
1. The cost effectiveness evaluation for boilers with similar characteristics (i.e., flow rates, emissions) was combined in this analysis.
2. For cyclones, the highest potential emissions from similar source types (boilers, gensets, etc.) is used.
3. For cyclones, a control efficiency of 90% is assumed.

As shown in Table 2-4, installation of add-on controls for PM is cost prohibitive. The use of natural gas as the primary fuel and good combustion practices are considered BART for PM for the package boilers.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

2.5 BART DETERMINATION - TURBINE/GENSETS (EU 55-59)

This section of the BART analysis identifies and describes the potentially available retrofit control technologies for Turbine Gensets (EU 55-59) at the facility. Related summary information on retrofit option costs, and energy and non-air quality environmental impacts of control options and the visibility impacts analysis is also presented. The final BART determinations suggested by Agrium are also presented in these sections. As indicated earlier in this document, the specified determinations will be considered as BART for purposes of this study

Available Control Technologies for NO_x - Turbines/Gensets

The following is a list of control technologies identified which are potentially capable of controlling NOx emissions from the turbines at the facility.

- Combustion Control (including Low NO_x and Ultra Low-NO_x burners);
- Staged Combustion Air (SCA);
- Selective Non-Catalytic Reduction (SNCR);
- Selective Catalytic Reduction (SCR);
- Ultra Low- NO_x Burners and SNCR; and
- Ultra Low- NO_x Burners and SCR.

Agrium noted that based on their review, the use of ULNB and ULNB+SCR appear to be the most common control technologies used to reduce NO_x emissions from these sources.

Each of the control methods identified above are considered technically feasible for controlling NO_x emissions from the turbines, with the exception of SNCR. The exhaust temperature from the turbines is too low to render SNCR feasible; therefore, no further analysis of the SNCR was conducted.

No further analysis of SCA was conducted because Agrium cited potential limitations that may render it technically infeasible, due to flame stability and flame temperature issues which will affect the heat flux distribution of the heater. These factors would need to be investigated in an in-depth engineering review.

No additional analysis of ULNB+SNCR or ULNB+SCR combination technologies was done based on the expectation that they won't result in a significant benefit over using a ULNB or SCR alone. It was Agrium's belief that the cost of combination of controls such as SCR and ULNB will be significantly higher than the costs of each of the individual control options without a proportional increase in control efficiency.

The cost effectiveness was evaluated for three types of add-on controls, including LNB, ULNB, and SCR. The costs associated with retrofitting the add-on control technologies on the Turbines/Gensets are summarized in Table 2-5 below.

Table 2-5 - Summary of Cost Effectiveness Evaluation for NO_x Controls on Turbines/Gensets

Source IDs	Source Description	Add-on Control Equipment	Cost Effectiveness ($/ton)
55-59	Turbine/Gensets	LNB	12,400
		ULNB	1,400
		SCR	7,700

Installing LNB or SCR on the turbines is not considered cost-effective. In addition, the environmental impact of the ammonia emissions associated with the SCR is not considered favorable for the use of SCR on the turbines.

The predicted cost effectiveness for the retrofit of ULNB on the turbines is within the range that is economically feasible. However,. when considering visibility modeling results the visibility cost effectiveness associated with installation of ULNB on the turbines is in excess of $780,000/deciview and as high as $4,500,00/deciview depending on the Class I area under consideration. While there is no guidance on such a relationship, Agrium does not believe that the excessive cost incurred warrants the resultant potential net visibility benefit associated with a ULNB retrofit on the turbines.

Notwithstanding the above BART determination, should Agrium re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

SO_2 CONTROLS - Turbines/Gensets

The only applicable control technology available for evaluation for the turbines is a wet gas scrubber. This technology was deemed technically feasible. Based on EPA's cost control manual guidance for wet gas scrubbers, the cost effectiveness value associated with SO_2 reductions is estimated to be over $4,570,000/ton, which is not considered reasonable. Therefore, the use of good combustion practices and firing of natural gas in the turbines is considered to be BART.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

PM CONTROLS - Turbines/Gensets

The following is a list of potentially available control technologies for controlling PM_{10} emissions from the turbines:

- Good Combustion Practice;
- Wet Scrubbing;
- Cyclone;
- Dry/wet electrostatic precipitation; and
- Fabric Filtration/baghouse;

Agrium's review of the EPA's RBLC database (see summary in Appendix B) found that the use of natural gas and good combustion practices were the most commonly used control technologies for natural gas fired turbines.

Agrium determined that all of the above control technologies were technically feasible, and conducted further analysis of Baghouse, Cyclone, Dry ESP, and Wet Scrubbers.

Table 2-6 - Summary of Cost Effectiveness for Add-on PM Controls on Turbines/ Gensets

Source ID	Source Description	Add-on Control Equipment	Cost Effectiveness ($/ton)
55-59	Turbine/Gensets	Baghouse	80,000
		Cyclone	50,240
		Dry ESP	33,900
		Wet Scrubber	59,500

Based on Agrium's summary cost information reflected in Table 2-6 above, Agrium concluded that the installation of add-on PM controls on the turbines is not economically feasible. The use of natural gas and good combustion practices are considered BART for PM for the turbines.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

2.6 BART DETERMINATION - UREA PRILL TOWER (EU 27) AND GRANULATORS A/B (EU 35/36)

PM CONTROLS – Prill Tower & Granulators

The only pollutant emitted from the prill tower and the granulators is particulate matter (PM). The emissions from the prilling process are a result of the carryover of fumes and particles through the prill cooling water. The particles formed in the prilling process are finer due to the constant attrition of the particles due to collision with the tower. The emissions from the granulation process are larger size particles due to the lower air flow rate in this process. PM emissions from both processes depend on the ambient air and air flow temperature, flow rate, and the change in the crystal state of ammonium nitrate.

Agrium has indicated that the potential control options available for both of these sources would be similar because the methodology for generation of emissions is similar for both sources. Therefore, the control technology review for the granulator and prill tower was combined in this evaluation. The following is a list of potentially available control technologies for controlling PM_{10} emissions from these units:

- Wet Scrubber with Mist Eliminator; and
- Wet ESP.

Based on a review of available literature and EPA's RBLC database (see summary in Appendix B), only wet scrubbers have been installed on similar sources at other facilities; however, given the potential applicability of a wet ESP for these sources, Agrium further evaluated this control option. Agrium has indicated that at the time of this evaluation, no source has been identified as employing a wet ESP

Cost estimates done using EPA's cost control manual are summarized in Table 2-7 below.

Table 2-7 - Summary of Cost Effectiveness for Granulators and Prill Towers

Source ID	Source Description	Add-on Control Equipment	Cost Effectiveness ($/ton)
27	Urea Prill Tower	Wet ESP	850
		Wet Scrubber	1,400
35/36	Granulators	Wet ESP	20,000
		Wet Scrubber	32,000

Add on controls for granulators are cost prohibitive. The cost analysis for add on controls for the prill tower shows that the control technologies, especially the wet ESP, is economically feasible. Potential environmental impacts from these control systems are summarized below:

- Wet scrubbers are known to result in a visible plumes due to the formation of aerosols, which can cause transportation, other visibility impacts, and socio-economic impacts;
- The wastewaters generated from these control systems could have a detrimental environmental impact that will require additional treatment. . This is a particular concern given the high nitrogen content of the particulate that would be captured in the resulting effluent from this source, and the fact that the discharge of the source is direct to Cook Inlet. Should the facility be required to construct additional facilities to treat this potential new wastewater, the overall cost of the control system would be significantly increased, making the option economically infeasible.

In addition, the wet ESP technology is one that has yet to be demonstrated on a similar source, causing further concern that there may be operational issues on both the process and the control device.

Based on the items presented herein, and in particular due to the insignificant predicted visibility benefits, as well as the other environmental and socio-economic impacts from these control systems, the wet ESP and wet scrubber technologies are not considered as a viable BART options for the granulators and prill tower. The continued use of best management practices to operate these emission sources is proposed by Agrium as BART.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

2.7 BART DETERMINATION - UREA LOADING WHARF

PM_{10} CONTROLS – Urea Loading Wharf

Agrium conducted a literature and RBLC review (see summary in Appendix B) to determine the most common control option used to reduce PM emissions from fugitive sources such as the urea unloading operations is the use of water/chemical dust suppressants. Add-on control (end-of-pipe) options are not technically feasible for this type of operations since the emissions are fugitive in nature and can not be captured and directed into a manageable flow stream. Due to the extremely low sub-zero temperatures for a majority of the calendar year in the Kenai area, the use of water as a suppressant is not be a feasible option due to problems with freezing. Application of chemicals is considered more suitable in warmer and dryer climates; therefore, the use of chemical suppressants is also not considered technically feasible for the Agrium facility. Therefore, water and chemical suppressants are eliminated as technically infeasible options and are not included in further analysis. The use of best management practices to control fugitive emissions is considered BART for this process.

The above BART determination notwithstanding, should Agrium decide in the future to re-commence operations at the Kenai facility, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

2.8 BART DETERMINATION - PRIMARY REFORMERS (EU 2 and 12)

In the ammonia production process, natural gas reacts with steam and is passed through the catalyst tubes in the reformer heater. The burners in the reformers are natural gas fired. The visibility impairing pollutants emitted from the reformers are NO_x, SO_2, and PM_{10}.

NO_X CONTROLS – Primary Reformers

The following is a list of control technologies identified which are potentially capable of controlling NO_x emissions from the primary reformers at the facility.

- *Combustion Control -Low* NO_x *Burners or Ultra Low* NO_x *Burner*
- *Staged Combustion Air*
- *Selective Catalytic Reduction*
- *Ultra low NOx burners+Selective Catalytic Reduction*

Each of the control methods identified above are considered technically feasible for controlling NO_x emissions from the reformers, with the exception of SNCR. The exhaust temperature from the reformers is too low to render SNCR feasible; therefore, no further analysis of the option is conducted in this analysis.

While SCA appears to be technically feasible, there are potential limitations which would shift this to a technically infeasible option due to flame stability and flame temperature issues which will affect the heat flux distribution of the heater. This potential change in the heat flux distribution would adversely affect the facility's process operations. No additional analysis was conducted for the SCA technology.

The use of ULNB+SNCR or ULNB+SCR combination technologies were not analyzed further because Agrium did not expected them to result in a significant benefit over using a SNCR or SCR alone. The cost of combination of controls such as SCR and ULNB was anticipated to be significantly higher than the costs of each of the individual control options without a proportional increase in control efficiency, and therefore wasn't examined by Agrium.

The cost analysis for LNB, ULNB, and SCR is summarized in Table 2-8 below.

Table 2-8 - Summary of Cost-Effectiveness for NO_x Controls on Primary Reformers

Source ID	Source Description	Cost Effectiveness ($/ton)		
		LNB	ULNB	SCR
2	Primary Reformer	7,300	4,000	12,300
12	Primary Reformer	N/A*	7,200	10,400

*Low NO_x burners installed in 1985.

The only control technology that is potentially cost effective was ULNB on Primary Reformer 02. The other technologies were listed as not being cost effective.

In addition, the environmental impact of the ammonia emissions associated with SCR is not considered favorable on these sources. Agrium identified additional issues associated with SCR including the need to retrofit the current primary reformer duct work. The convection section of the existing reformers would need to be rebuilt so that flue gas could be ducted from the existing convection section (if reused) at the temperatures required for the catalyst to operate and directed to an SCR duct containing the new catalyst. The exhaust from the SCR unit would then need to be directed back to the reformer duct work for heat recovery. However, the remaining heat recovery available would be drastically reduced causing operational concerns and upsetting the overall reformer process. At this time, there is no space available in the reformer duct work to accommodate the SCR flow constraints which would require the installation of a new convection section. To accommodate this convection section issue, along with other anticipated retrofit concerns, an escalated retrofit cost item will need to be included in the cost effectiveness evaluation. These issues would need to be evaluated further in a detailed engineering review.

Agrium proposed that the use of good combustion practices and use of natural gas are considered BART for NO_x emissions associated with the reformers.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

SO_2 CONTROLS – Primary Reformers

The primary reformers burn natural gas as the primary fuel and process gas as a back-up. The only control option considered available and potentially technically feasible is wet scrubbing. Based on EPA's cost control manual guidance for wet gas scrubbers, the cost effectiveness associated with SO_2 reductions are summarized in the following table.

Table 2-9 - Summary of Cost Effectiveness Evaluation for SO_2 Controls on Primary Reformers

Source ID	Source Description	Add-on Control Equipment	Cost Effectiveness ($/ton)
02	Primary Reformer	Wet Scrubber	908,000
12	Primary Reformer	Wet Scrubber	976,000

As seen from the above table, the costs associated with installing add-on controls are cost prohibitive. Therefore, no additional controls are proposed to reduce SO_2 emissions from these units. The continued use of good combustion practices and use of natural gas as the primary fuel are considered BART to reduce SO_2 emissions from the primary reformers.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

PM_{10} CONTROLS – Primary Reformers

The control options available for reducing PM emissions from the reformers include:

- *Good combustion;*
- *Wet scrubbing;*
- *Baghouse; and*
- *Dry ESP.*

Each of the control options identified above are considered potentially technical feasible for retrofit on the primary reformers

Table 2-10 - Summary of Cost Effectiveness Evaluation for PM Controls on Primary Reformers

Source ID	Source Description	Add-on Control Equipment	Cost Effectiveness ($/ton)
02	Primary Reformer	Baghouse	57,600
		Dry ESP	15,800
		Wet Scrubber	19,800
12	Primary Reformer	Baghouse	38,000
		Dry ESP	15,800
		Wet Scrubber	21,200

None of the analyzed control technologies are cost effective. Agrium proposed the use of good combustion practices and use of natural gas as BART for PM emissions for the reformers.

Notwithstanding he above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

2.9 BART DETERMINATION - CO2 COMPRESSORS (EU 24 and 25)

NO_X CONTROLS – CO_2 Compressors

The following is a list of control technologies identified which are potentially capable of controlling NOx emissions from the CO_2 Compressors at the facility.

- *Combustion Control -low NOx burners or ultra low NOx burner*
- *Staged Combustion Air*
- *Selective Catalytic Reduction*
- *ULNB+SCR*

Each of the control methods identified above are considered technically feasible for controlling NO_x emissions from the reformers, with the exception of SNCR. The exhaust temperature from the reformers is too low to render SNCR feasible; therefore, no further analysis of the option is conducted in this analysis.

While SCA appears to be technically feasible, there are potential limitations which would shift this to a technically infeasible option due to flame stability and flame temperature issues which will affect the heat flux distribution of the heater. This potential change in the heat flux distribution would adversely affect the facility's process operations. No additional analysis was conducted for the SCA technology.

The use of ULNB+SNCR or ULNB+SCR combination technologies were not analyzed further because Agrium did not expected them to result in a significant benefit over using a SNCR or SCR alone. The cost of combined controls such as SCR and ULNB was anticipated to be significantly higher than the costs of each of the individual control options without a proportional increase in control efficiency, and therefore wasn't examined by Agrium.

The cost analysis for LNB, ULNB, and SCR is summarized in Table 2-11 below.

Table 2-11 - Summary of Cost Effectiveness Evaluation for NO_x Controls on Compressors

Source ID	Source Description	Add-on Control Equipment	Cost Effectiveness ($/ton)
24, 25	Compressors	LNB	7,100
		ULNB	700
		SCR	8,850

The installation of LNB or SCR on the turbines is not considered cost-effective. In addition, the environmental impact of the SCR-related ammonia emissions as previously discussed for other BART-eligible sources is not considered favorable for the use of SCR on the compressor engines.

The predicted cost effectiveness for the retrofit of ULNB on the compressor engines is in a range that may be considered reasonable. However, when considering visibility modeling results the visibility cost effectiveness associated with installation of ULNB on the compressor engines is in excess of $332,000/deciview and as high as over $2,500,000/deciview depending on the Class I area under consideration. While there is no guidance on such a relationship, Agrium does not believe that the excessive cost incurred warrants installation given the resultant potential net visibility benefit associated with a ULNB retrofit on the compressor engines.

Agrium proposed that the use of good combustion practice and firing of natural gas is considered BART for the compressor engines.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

SO_2 CONTROLS – CO_2 Compressors

The only control option available and technically feasible is wet scrubbing. Based on estimates from EPA's cost control manual for wet gas scrubbers, the cost of SO_2 reductions is estimated to be more than $603,000/ton, which is considered to be cost prohibitive. Therefore, Agrium proposed continued use of good combustion practices and natural gas in the compressor engines to be BART, and no additional add on controls proposed.

Notwithstanding the above BART determination notwithstanding, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

PM CONTROLS - CO_2 Compressors

The following is a list of potentially available control technologies for controlling PM_{10} emissions from the turbines:

- Good Combustion Practice;
- Wet Scrubbing;
- Cyclone;
- Dry/wet electrostatic precipitation; and
- Fabric Filtration/baghouse.

Based on Agrium's review of EPA's RBLC database (see summary in Appendix B), good combustion practice is the most common control to limit PM emissions for compressor engines. Each of the control options listed above are considered technically feasible for the compressor sources at the facility. Cost-effectiveness values associated with the installation of add-on PM controls for compressors was conducted. Using estimates from EPA's cost control manual, the costs to reduce PM emissions associated with these control options are summarized in Table 2-12 below.

Table 2-12 - Summary of Cost Effectiveness Evaluation for PM Controls on Compressors

Source ID	Source Description	Add-on Control Equipment	Cost Effectiveness ($/ton)
24, 25	Compressors	Baghouse	80,000
		Dry ESP	53,500
		Cyclone	11,870
		Wet Scrubber	80,000

As shown in Table 2-12, none of the control technologies reviewed are cost effective. Agrium proposed the use of good combustion practices and use of natural gas as BART for PM emissions for the compressor engines.

Notwithstanding the above BART determination, should Agrium decide to re-commence operations at the Kenai facility in the future, Agrium must submit for Department approval a detailed revised BART analysis that must address the findings provided in Appendix A.

3 VISIBILITY IMPACTS EVALUATION

Pursuant to 40 CFR 51, Appendix Y and 18 AAC 50.260, the BART determination must include an evaluation of the impacts associated with the installation of various control options regarding potential visibility benefits in Class I areas. Agrium submitted a CALPUFF visibility assessment modeling protocol on January 29, 2008; with revised information submitted on March 11, 2008 in response to Department question. The Department approved Agrium's revised protocol on April 18, 2008.

The refined CALPUFF analysis conducted by Agrium was used to support the control analysis and preliminary determinations submitted on July 28, 2008. The visibility impacts have been determined using the CALPUFF modeling system according to the following sequence for the retrofit control technology options presented in Section 2:

- Model pre-control (baseline) emissions
- Model individual post-control emissions scenarios
- Determine degree of visibility improvement
- Factor visibility modeling results into BART "five-step" evaluation, including a visibility cost effectiveness metric expressed as cost of control option per deciview improvement ($/DV)

The following sections provide the findings associated with the methods used by Agrium to evaluate the visibility impacts at both the Tuxedni and Denali Class I areas; and the potential visibility improvements associated with the retrofit technologies evaluated by Agrium.

3.1 CALPUFF MODELING APPROACH

The approach used by Agrium in the visibility modeling analysis is described in Section 9 of their BART control analysis report. The following discussion presents a review of, and findings related to, the Agrium CALPUFF visibility modeling analyses.

<u>BART-Eligible Source Emission Rates and Stack Parameters</u>

Table 2-1 of the modeling protocol presented the emissions inventory data to be used in Agrium's modeling analysis. Review of the CALPUFF input files provided by Agrium with the July 28, 2008 BART control analysis indicates that the Table 2-1 protocol parameters have been used in the CALPUFF visibility modeling. The following summarizes the information used in the CALPUFF input files, and any findings relating to review of this information:

- The baseline NO_x, SO_2 and PM_{10} emission rates used in the CALPUFF modeling are consistent with the emission rates proposed by Agrium in Table 2-1 of the January 29, 2008 protocol. These emission rates reflect the maximum 24-hour pollutant emission rates at nominal plant capacity which, per Agrium, last occurred in calendar year 2002. Agrium believes these emission rates are a conservative estimate of the emissions that may occur if the plant restarts.

- In addition to the NO_x, SO_2 and PM_{10} emission rates used in the analysis as discussed above, BART eligible units 27 (Urea Prill Tower) and 35/36 (Granulators A/B) also included ammonia (NH_3) emissions modeled in CALPUFF.

- BART eligible unit stack exit parameters used in the CALPUFF modeling are consistent with the same parameters proposed by Agrium in Table 2-1 of the January 29, 2008 protocol.

- Each BART eligible unit has been modeled in CALPUFF as a point source, except the Urea Loading Area which has been modeled as an area source, consistent with the Departments comments of April 18, 2008.

- For each BART eligible source, all PM_{10} emitted has been assumed as $PM_{2.5}$, which is consistent with the protocol document.

Except for direct modeled NH_3 emissions from EU27, 35 and 36, the data described by Agrium in their BART report and used in the CALPUFF input files are consistent with the protocol. The exception warrants additional discussion. Agrium did not propose the use of direct NH_3 emissions in their modeling protocol, nor was the inclusion of direct NH_3 emissions expected since they were not included in the WRAP-RMC modeling analysis. Since the modeling analysis is supposed to be consistent with the approved protocol, per 18 AAC 50.260(h)(3)(b), Agrium's analysis could be rejected for procedural reasons. In discussing this issue with the Department, the Department decided that the best approach would be to note the inconsistency but to proceed with a conditional approval. The Department made this decision for the following reasons:

1) The facility is not operating (which means there are no current visibility impacts);
2) Agrium will need to submit a revised analysis prior to restarting the facility; and
3) The inclusion of direct NH_3 emissions has technical merit.

Agrium will nevertheless need to resolve the procedural inconsistency described above prior to restarting the facility. Appendix A also contains a list of technical issues that Agrium would need to address in a revised submittal. These items are also summarized below.

CALPUFF Modeling Procedures

The CALPUFF modeling methods and the related model input options selected for use in this study have been reviewed for consistency with the protocol and related BART guidance documents. Applied modeling procedures and any findings are summarized as follows:

- CALPUFF modeling performed for each of three years (2002 - 2004) with Department approved CALMET meteorological data prepared using revised MM5 data.
- EPA-approved CALPUFF version 5.8, level 070623
- EPA CASTNET hourly ozone data from Denali, using 40 ppb default for missing hours
- A background ammonia concentration of 0.5 ppb (increased from 0.1 ppb as initially proposed in the protocol document, which is compliant with comments made by the Department in the April 18, 2008 protocol approval letter)
- Regulatory default model options when such options are specified
- National Park Service discrete receptor locations and elevations for Denali National Park and the Tuxedni Wilderness (http://www2.nature.nps.gov/air/maps/Receptors/index.cfm)
- Aerodynamic building downwash not used in the modeling analysis

- CALPUFF computational domain consistent with the CALMET meteorological domain (NX=270, NY=325)

In summary, the data described by Agrium in their BART report and used in the CALPUFF input files are consistent with the protocol. Other findings associated with the review of this information that should be addressed by Agrium if future reactivation of the plant is planned are contained in Appendix A.

CALPOST Modeling Procedures

The CALPUFF post-processing methods of CALPOST and the related model input options selected for this study have been reviewed for consistency with the protocol and related BART guidance documents. Agrium did not submit the actual CALPOST modeling files with the August 2008 BART control analysis submittal; instead, only summary results files have been provided by Agrium's modeling consultant, ERM. As such, the CALPOST modeling review has focused on the proposed modeling procedures specified by ERM in the protocol; related Department findings stated in the protocol approval; and the modeling procedures discussed in Section 9 of the August 2008 BART control analysis report. Since Agrium will need to submit a revised BART analysis prior to restarting the facility, the summary results files have been accepted for this review. Agrium will need to submit all modeling files at such time as a revised BART analysis is submitted in order to confirm the modeling findings summarized below:

- Presumed use of EPA-approved CALPOST version 5.6394, level 070622, which is consistent with the Department's comments in the April 18, 2008 protocol approval letter (it is noted that the Department protocol approval instructed that the regulatory version of CALPOST, i.e., version 5.6394, level 070622, be used in the visibility modeling and it is presumed Agrium complied with this requirement, and this must be confirmed in any future submittal);
- Presumed use of particle growth curve f(RH) for hygroscopic species based on EPA (2003) f(RH) tabulation (it is noted that the modeling protocol indicated EPA (2003) methods would be utilized in the CALPOST modeling, and this must be confirmed in any future submittal);
- Presumed use of CALPOST default extinction efficiencies for PM fine (PMF), PM coarse (PMC), ammonium sulfate, ammonium nitrate, organic carbon (OC), and elemental carbon (EC) (it is noted that use of default values is presumed, and this must be confirmed in any future submittal);
- Presumed calculation of background extinction and change to extinction using the recommended CALPOST Method 6 (MVISBK=6) (it is noted that the modeling protocol and a confirmatory March 11, 2008 email from ERM indicated this option would be selected in the CALPOST modeling, and this must be confirmed in any future submittal);
- Presumed use of monthly relative humidity adjustment factors specific to each Class I area as taken from Table A-3 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B03-005 (September 2003) (it is noted that the modeling protocol indicated the EPA (2003) Class I area specific relative humidity factors for Denali and Tuxedni would be used in the CALPOST modeling, and this must be confirmed in any future submittal);
- Presumed use of As reflected in the protocol, annual average natural background aerosol concentrations as taken from Table 2-1 of *Guidance for Estimating Natural Visibility*

Conditions Under the Regional Haze Rule, EPA-454/B03-005 (September 2003) (it is noted the modeling protocol and a confirmatory March 11, 2008 email from ERM indicated this data would be selected in the CALPOST modeling, and this must be confirmed in any future submittal);

- Since ERM indicated that Method 6 (MVISBK=6) of CALPOST version 5.6394 would be used in this modeling study, the "old" IMPROVE equation would be reflected in the study results. This notwithstanding, the Department approved use a "new" IMPROVE equation which has been applied by Agrium.

  As indicated in Section 9.2 of the Agrium BART control analysis report, visible impacts associated with the "new" equation, which are reflective of the 2005 recommendations made by the IMPROVE Steering Committee ("Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data", IMPROVE technical subcommittee for algorithm review, January 2006), have been computed using Class I site-specific sea salt concentrations input to the spreadsheet methodology developed by Dr. Ivar Tombach ("Instructions: A Postprocessor for Recalculating CALPOST Visibility Outputs with the New IMPROVE Algorithm - Version 2", October, 14 2006). This procedure must be confirmed in any future submittal and the related spreadsheets must be provided at the time of future submittal.

In summary, while the CALPOST modeling files have not been submitted, based on Agrium's BART visibility modeling protocol; the Department's comments as reflected in their protocol approval; and Section 9 of Agrium's BART control analysis report, the visibility modeling analysis procedures appear to be consistent with the approved protocol. As specified above, any future modeling to support a revised BART submittal must include the related CALPOST modeling files. Agrium must also address other findings contained in Appendix A prior to future reactivation of the plant.

3.2 VISIBILITY MODELING RESULTS

As supported in EPA's BART rules and guidelines, and as specified in the protocol, when conducting a visible impacts modeling study based on multiple years of modeling (i.e., 3-years for this study) source impacts are to be based on use of the predicted 98th percentile change to the daily Haze Index (HI) expressed in units of deciviews. The metric against which predicted values of delta-HI cab be compared for purposes of establishing a significant cause or contribution to impairment of visibility is a 0.5 daily deciview change.

Table 9-1 of the Agrium BART control study report presents a summary of the highest 98th percentile modeling results from the 3-years of modeling at each Class I area for the base-case emissions scenario. The CALPUFF modeling results demonstrate that the total visible impacts from all BART-eligible sources exceeds the 0.5 daily deciview metric at both the Tuxedni and Denali Class I areas and all three years of modeling. The modeling results also indicate source impacts at Tuxedni to be almost four times greater than at Denali.

Tables 9-2 through 9-4 of the Agrium BART control study report present summaries of, among other data, the modeled improvement in visible impacts associated with the retrofit control options considered for each BART-eligible emission unit and visibility impairing pollutant (NO_x, SO_2 and PM_{10}); and related visible cost effectiveness values ($/deciview improvement).

3.3 VISIBILITY MODELING CONCLUSIONS

A detailed review of the Agrium BART-eligible source visibility modeling analysis has been conducted for the Kenai facility. It has been determined that the modeling analyses are seemingly in conformance with the January 29, 2008 protocol submitted to, and approved by, the Department on April 18, 2008.

The above notwithstanding, findings pertaining to a review of the available modeling data files and related Section 9 of the Agrium BART control analysis report have been made and they are contained in Appendix A of this document. Agrium will need to address the Appendix A comments, and provide the CALPOST modeling files as discussed above, prior to restarting the Kenai facility.

4 AGRIUM BART CONTROL ANALYSIS REPORT FINDINGS AND CONCLUSIONS

The objective of this review has been to document Enviroplan's findings regarding Agrium's July 28, 2008 BART control analysis in terms of compliance with 18 AAC 50.260(e) through (h). Proposal of a preliminary BART determination for each BART-eligible source at this facility, consistent with 18 AAC 50.260(j), is also an object of this review. This findings report concludes that the Agrium BART control analysis complies with 18 AAC 50.260(e) through (h); and the control options proposed herein by Agrium are conditionally accepted as preliminary BART pursuant to 18 AAC 50.260(j). For each combustion related BART eligible source (i.e., 5 package boilers, five turbine/gensets, two primary reformer and two CO2 compressor engines), use of natural gas fuel and good combustion practices is preliminary BART; and for the Urea Prill Tower, Granulators A/B and materials handling at the Urea Loading Wharf, good management and operating practices is preliminary BART.

The facility is currently not operating due to an unavailability of natural gas, which is a primary feedstock used for production at the site. It is unknown when the facility will initiate production in the future; however, this BART analysis was completed by Agrium for submittal to the Department to fulfill the regulatory requirement of the Alaska BART regulation, 18 AAC 50.260. Due to the non-operational status of the plant, the aforementioned determinations have been conditionally deemed by the Department as preliminary BART for each eligible source. However, the Department intends to modify the Title V operating permit to require that, prior to re-commencing production at this plant, Agrium will submit for approval a detailed revised BART control analysis consistent with 18 AAC 50.260. Additionally, at such time that Agrium decides to re-commence production at the facility, Agrium must address all findings specified in Appendix A when preparing a detailed revised BART control analysis.

APPENDIX A - SPECIFIC FINDINGS ASSOCIATED WITH REVIEW OF THE AGRIUM BART CONTROL ANALYSIS REPORT

Findings Report
Agrium Kenai Nitrogen Operations (Agrium)
Best Available Retrofit Technology (BART) Evaluation

Prepared for

State of Alaska
Department of Environmental Conservation
Division of Air Quality

ADEC Contract No. 18-3001-17
NTP No. 18-3001-17-7A

Prepared by
Enviroplan Consulting
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Agrium Kenai Nitrogen Operations (Agrium) owns and operates an ammonia and urea production facility in Kenai, Alaska. Agrium is subject to the requirements of the Federal Regional Haze Rule, 40 CFR Parts 51.300 through 51.309, and 40 CFR Part 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule*; and the Department's regulation relating to BART, 18 AAC 50.260. The modeled visibility impacts from Agrium have been determined to exceed the BART exemption threshold of 0.5 deciviews, as defined in 18 AAC 50.260(q)(4). As such, Agrium is required to submit a case-by-case BART control analysis for each BART-eligible unit at the facility and related visibility impairing pollutants (VIPs). Agrium submitted the BART control analysis on July 28, 2008. In summary, Agrium has evaluated the pollution control alternatives for each BART-eligible unit; the potential reduction in NOx, SO2, and PM10 emissions as the VIPs; the cost of each control option; and the degree of visibility improvement associated with the control options.

The above notwithstanding, the plant has not been in operation since 2006 due to an unavailability of natural gas, which is a primary feedstock used for production at the site. The BART evaluation provided by Agrium is conceptual in nature and no detailed engineering studies have been performed to determine site-specific constraints and/or retrofit capability for individual units. Given the non-operational status of the plant, the Department has conditionally accepted the BART determinations provided by Agrium for each affect unit. The actual BART determinations accepted by the Department are contained in the main body of this findings report. The Department will modify the Part 71 operating permit for this facility to require that the Permittee submit a revised and more detailed BART analysis for approval prior to commencing production activities at any BART-eligible emission unit. The Part 71 modification satisfies the requirement of 18 AAC 50.260(j) for this plant

Since the Part 71 permit will require Agrium to submit a revised BART analysis for approval prior to commencing any future production at this plant, Agrium's July 28, 2008 BART control analysis report has been reviewed to determine whether it is consistent with the applicable requirements of 18 AAC 50.260; and whether the conclusions are technically sound, reasonable and substantiated. Review of the July 2008 analysis lead to the findings specified below. Agrium should address each specified finding if a future detailed BART analysis is prepared and submitted for review and approval by the Department. The following findings are presented in order of the sections contained in Agrium's July 28, 2008 BART analysis, except for the findings associated with supplemental information. The supplemental information findings pertain to that information provided by Agrium on October 9, 2008 as noted below.

<u>Findings Associated with Supplemental Information Provided by Agrium</u>

Agrium provided supplemental information on October 9, 2008 in response to Enviroplan's cursory review findings dated September 19, 2008. The following findings and need for further clarification and/or information relate to Agrium's response to the September 19, 2008 cursory review.

1. Detailed costing information to support the control options described in the BART control option analysis report was not initially supplied to the Department. This information was supplied in response to the September 19, 2008 cursory findings. If a detailed BART control analysis is prepared and submitted in the future, Agrium should plan to include all detailed costing information at the time of report submittal, including related spreadsheets or other similar data sets.

2. Items #3 and #4 of the cursory review requested Agrium to provide additional justification and related detailed information supporting the decision not to evaluate combined control technologies. Agrium provided the following response:

   For package boilers (emission units 42-44, 48, 49):
   As presented in the BART analysis, the Kenai facility is currently non-operational; therefore, any significant design evaluations and modifications would have to be conducted upon re-start. Similarly for a combination of controls such as LNB+FGR and ULNB+SCR, the control efficiency is site-specific and would have to be verified by detailed design evaluation. It should also be noted that a combination of LNB and FGR is more common in industrial application.

   The cost of combination of controls such as SCR and ULNB would be significantly higher than the costs these controls individually, without a significant proportional increase in control efficiency. The cost effectiveness estimates presented in the BART analysis were calculated by dividing the sum of the total NOx controlled by the sum of the total annualized costs for SCR or ULNB. The same methodology was presented in the ACT document for ICI Boilers. Using the methodology described above, for the package boilers, the total annualized cost and cost effectiveness of installing a combination of ULNB and SCR will be more than $400,000/year and $11,000/ton, respectively. The cost of this control option is considered to be above an economically reasonable range, especially given the uncertainties in retrofitting these technologies on existing units. For this reason and for the other energy and environmental concerns raised by this combination of technologies as described in the original Agrium submittal, this combination of controls should not be considered BART.

   For turbine/genset (emission units 55-59), Primary Reformers (Emission units 2 and12) and CO2 compressors (emission units 24/25):

   The cost of combination of controls such as SCR and ULNB will be significantly higher than the costs of each of the individual control options without a proportional increase in control efficiency. The cost effectiveness estimates were calculated by dividing the sum of the total NOx controlled by the sum of the total annualized costs for SCR and ULNB. The same methodology was presented in the ACT document for ICI Boilers. Using the methodology described above, the total annualized cost and cost effectiveness of installing a combination of ULNB and SCR will be more than $470,600/year and $4,900/ton, respectively. The cost of this control option is considered to be above an economically reasonable range, especially given the uncertainties in retrofitting these technologies on existing units. For this reason and for the other energy and environmental concerns raised by this combination of technologies as described in the original Agrium submittal, this combination of controls should not be considered BART.

   In each of these cases, the combined control technology represents the most efficient technically feasible control scenario. In their response, Agrium references the average cost effectiveness ($/ton) of each individual control technology and does not perform a detailed cost analysis of the specific combined control technologies. This response is not in accordance with the guidance received from Don Shepard of the National Park Service via email on September 23, 2008. In that correspondence, he stated that:

"I am especially concerned that separating a strategy that combines multiple technically feasible control options into components that are then evaluated individually will lead to a situation where one component is relatively cheap (on a $/ton basis) while the other is relatively expensive. For example, consider a new PC boiler--the "standard" BACT is now Combustion Controls + SCR. However, if one were to evaluate each component separately, an argument could be made that just doing the combustion controls is so much more cost-effective than including the SCR that SCR is not economically feasible. We must keep in mind that both BACT and BART are not necessarily the most cost-effective solutions. (If that were the case, we would probably stop with multi-cyclones for PM control instead of ESPs and baghouses.) What we are really trying to find are the control strategies--whether they be individual or combinations--that are reasonably cost-effective, but not necessarily the cheapest on a $/ton basis. So, if the cost-effectiveness of a combination strategy is reasonable, it passes the economic feasibility test, even if one of its components is more cost-effective.

And, it would not be appropriate to simply sum the individual costs. (I assume that Agrium is not proposing to simply sum the $/ton values—that would clearly be erroneous.) For example, when evaluating the annual operating costs of SCR, the inlet and outlet NOx concentrations must be determined in order to estimate the size of reactor and the amount of reagent to be used. (You can use the attached workbook to explore the effects of those variables.) If we place combustion controls upstream of a SCR system, we reduce the capital and annual operating costs of the SCR compared to what they would be if the SCR had to do all of the work alone."

Agrium did not conduct the design parameter-based cost analysis for combined control technologies described by Don Shepard. However, Agrium did make reference to uncertainties associated with engineering design and retrofitting equipment that is not currently operations. Agrium should conduct additional analysis for combined controls as specified by Don Shepard if a detailed BART control analysis is prepared and submitted in support of future plant restart. At a minimum, in addition to the already evaluated low NOx and ultra-low NOx burner options, Agrium should fully evaluate such burner options in combination with over-fire air (OFA) and flue gas recirculation (FGR) systems. The October 9, 2008 response to Item 3 only qualitatively addressed such combined systems.

3. In addition to the above, Agrium's response to Item 3 as it pertains to Stage Combustion Air (SCA) indicates "*the usefuless of SCA is best demonstrated when incorporated into the design of LNB or ULNB products. Therefore, Agrium did not perform any cost analysis since it was technically inferior to other options as well as it being incorporated into typical LNB and ULNB designs.*" It is recognized that SCA is typically presented as a combined technology option with LNB and/or ULNB for combustion source NO_x control. However, the August 2008 Agrium BART control analysis and other related supplemental information do not specify whether the retrofit options of LNB and ULNB include OFA. As such, if a detailed BART control analysis is prepared and submitted in the future, Agrium should clearly state that the combustion source retrofit options of LNB and ULNB, including costs, includes OFA; or Agrium should include LNB/OFA and ULNB/OFA as NO_x control retrofit options.

4. Items #5 and #6 of the cursory review requested Agrium to provide additional information why an analysis was not completed and/or they should perform an impact analysis including cost of compliance for fuel switching on Boiler #42 (which burns fuel oil in addition to natural gas). In Agrium's response to Item #5, they provided the following additional explanation:

The Agrium Kenai facility is currently not operational due to the unavailability of natural gas which is used not only as a fuel, but as a raw material in the process. The capability of combusting used oil in this boiler has been disconnected and not expected to be used in the future. Upon a restart of the facility, the boiler would use pipeline quality natural gas as a fuel source.

In Agrium's response to Item #6, they provided the following additional explanation:

The Agrium Kenai facility is currently not operational due to the unavailability of natural gas which is used as a fuel source as well as a raw material in the process. Though, fuel switching might be a technically viable option, due to the unavailability of natural gas, the costs associated with the use of natural gas is determined to unreliable and speculative at best. Therefore, the cost effectiveness associated with switching from fuel oil to natural gas was not evaluated in this analysis. Upon re-start of the operations at the Kenai facility, Agrium will have to evaluate the option of switching to natural gas as BART for the boiler.

If a detailed BART control analysis is prepared and submitted in the future, Agrium should either confirm the use of only pipeline quality natural gas as fuel in Boiler 42; or conduct an additional control option analysis for fuel switching if Agrium decides to maintain waste oil fuel combustion at Boiler 42.

<u>Findings Associated with Section 1.2 of the Agrium BART Report</u>

5. Section 1.2 presents a summary table (Table 1-1) of the BART eligible unit baseline emission rates used to develop control option cost effectiveness estimates. The applicant indicates that calendar year 2002 has been used for this purpose since it represents the last year that the plant operated at nominal capacity before starting production scale-down and inactivity after 2006. If a detailed BART control analysis is prepared and submitted in the future, Agrium should confirm that 2002 production and VIP emission rates continue to reflect future production and VIP emission rates.

<u>Findings Associated with Section 3.1 of the Agrium BART Report (NOx Controls - Package Boilers)</u>

6. Section 3.1.1 identifies available controls for NOx. If a detailed BART control analysis is prepared and submitted in the future, Agrium should evaluate other combinations of NOx control as indicated in Item No. 2 above. Additionally, Agrium should consult specific manufacturers and vendors of SCR systems to confirm the amount of ammonia slip (ammonia emissions) expected for their systems. Further, Agrium should evaluate the potential applicability of innovative NOx control systems, including multi-pollutant control systems, as potential retrofit control technologies. Such available innovative NOx control technologies with potential application to the BART study include, but are not limited to, boosted over-fire air (e.g., MobotecUSA's ROFA® system), advanced SNCR control systems (e.g., MobotecUSA's Rotamix® system), Enviroscrub's multi-pollutant Pahlman™ process, and wet NOx scrubbing systems.

7. The control costing information presented in Section 3.1.3 (Package Boilers - NOx Controls) indicates that only select control options were considered as they represented the lower, middle and higher end of the range of emissions reduction. If a detailed BART control analysis is

prepared and submitted in the future, Agrium should evaluate other combinations of NOx control as indicated in Item No. 5 above.

8. Average cost effectiveness values (dollars/ton pollutant removed) are presented in Section 3.1.1, Table 3-1 for specified control options. Pursuant to 40 CFR Part 51, Appendix Y (BART Guidelines), Section IV, Agrium should have also evaluated and presented similar information for incremental cost controls, determined in accordance with Appendix Y. If a detailed BART control analysis is prepared and submitted in the future, Agrium should also compute and provide incremental costs determined in accordance with the BART Guidelines. It is also requested that additional relevant information be included in the cost summary table, including total annual cost for each control option as well as the control efficiency and tons per year of pollutant removed.

9. Section 3.1.3 states "*The control technology costs used in this analysis are primarily based on EPA's cost control manual and the cost estimates which represent 1990 dollar amounts*". This statement suggests that the 2002 "EPA Air Pollution Control Cost Manual" was used for cost estimation purposes. Use of this document would be consistent with 40 CFR 51, Appendix Y, Section IV, which references the prior version of this guidance document, the "OAQPS Control Cost Manual" and indicates the most current version of this document should be utilized when conducting an impact analysis (i.e., the 2002 version). This notwithstanding, the detailed cost estimation spreadsheets provided by Agrium consistently reference the outdated "OAQPS Control Cost Manual". As such, if a detailed BART control analysis is prepared and submitted in the future, Agrium should confirm use of the most current EPA cost manual and related cost spreadsheet tool (current EPA version is entitled "COST-AIR"); or revise their cost estimates to reflect the most current EPA control cost manual.

Findings Associated with Section 3.3 of the Agrium BART Report (PM10 Controls - Package Boilers)

10. Average cost effectiveness values (dollars/ton pollutant removed) are presented in Section 3.3.3, Table 3-3 for specified control options. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should revise the table consistent with Finding Item 7 above.

11. Section 3.3.3, Table 3-3 provides cost effectiveness determinations for two sets of two package boilers, Units 42 and 43 and Units 48 and 49. For both of these scenarios, it is not clear from the information presented in the table whether the cost effectiveness values reflect the summation of baseline emissions from two boiler and the capital/operating costs associated with one control device designed to control both boilers. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide greater clarity on the information presented in the table with respect to multiple emission units and one control device.

12. Section 3.3.3 indicates the assumed ESP and baghouse control efficiencies to be 95%. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide the basis for this control efficiency. Review of generally available information suggests that an efficiency of at least 99 percent can be achieved on a newly installed ESP or baghouse, therefore, Agrium should document the basis and source of their "assumed" efficiency and/or revise the cost analysis to reflect a higher control efficiency for these options.

Findings Associated with Section 4.1 of the Agrium BART Report (NOx Controls - Turbine/Genset)

13. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide similar information identified in Finding Items 5 - 8 above as applies to the turbine/genset units and identified control options of Section 4.1.

Findings Associated with Section 4.3 of the Agrium BART Report (PM10 Controls - Turbine/Genset)

14. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide similar information identified in Finding Items 9 - 11 above as applies to the turbine/genset units and identified control options of Section 4.3.

Findings Associated with Section 5.1 of the Agrium BART Report (PM10 Controls - Granulators and Prill Tower)

15. It is understood that the non-operational status of the plant has resulted in an engineering judgment estimate of 75% total PM capture and control efficiency for the wet ESP and wet scrubber control options. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide full documentation to support this efficiency assumption; and/or conduct a site-specific engineering study to determine the potential for retrofit of add-on controls (i.e., wet ESP and wet scrubber) and the resultant achievable total control efficiency of the system(s).

16. Average cost effectiveness values (dollars/ton pollutant removed) are presented in Section 5.3, Table 5-1 for specified control options. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should revise the table consistent with Finding Item 7 above.

17. Section 5.3 provides a summary of potential environmental impacts associated with the wet scrubber and wet ESP control options. Specifically, it is indicated that the wet scrubber is known to result in a visible plume due to the formation of aerosols. Since this rationale is being used to support ruling-out use of this system as a viable emissions control option, Agrium should provide sufficient explanation why the use of a mist eliminator, which is part of the control system, will not minimize and/or eliminate the potential for a visible plume occurring at each Class I area. Further, the rationale on wastewater generated from this system is qualitative only. Pursuant to 40 CFR 51, Appendix Y, the costs associated with ancillary equipment and operations (i.e., wastewater treatment) attributable to a control option should be quantified and included in the total cost of the control option. Therefore, should a detailed BART control analysis be prepared and submitted in the future, Agrium must better delineate the costs associated with the ancillary treatment operations.

Findings Associated with Section 6.1 of the Agrium BART Report (PM10 Controls - Urea Loading Wharf)

18. Section 6.1 indicates that add-on control options are not technologically feasible for the loading wharf operations since the emissions are fugitive in nature. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide a detailed description of the activities/equipment used at the loading wharf and explain why all or some of these activities cannot be enclosed and emissions reduced with viable add-on controls such

as a dust collector. Agrium should revise this section of the report as necessary to provide a cost analysis in accordance with 40 CFR 51, Appendix A, for any additional option(s) deemed technologically feasible.

Findings Associated with Section 7.1 of the Agrium BART Report (NOx Controls - Primary Reformers)

19. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide similar information identified in Finding Items 5 - 8 above as applies to the reformer units and identified control options of Section 7.1.

Findings Associated with Section 7.3 of the Agrium BART Report (PM10 Controls - Primary Reformers)

20. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide similar information identified in Finding Items 9 - 11 above as applies to the reformer units and identified control options of Section 7.3.

Findings Associated with Section 8.1 of the Agrium BART Report (NOx Controls - CO2 Compressors)

21. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide similar information identified in Finding Items 5 - 8 above as applies to the reformer units and identified control options of Section 8.1.

Findings Associated with Section 7.3 of the Agrium BART Report (PM10 Controls - CO2 Compressors)

22. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide similar information identified in Finding Items 9 - 11 above as applies to the reformer units and identified control options of Section 8.3.

Findings Associated with Section 9.0 of the Agrium BART Report (Visibility Impacts Evaluation)

23. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should revise the CALPUFF/CALPOST modeling and summary Tables 9-1 through 9-4 as necessary to account for any changes and additional control options evaluated in response to Finding Items 1 - 21 above; as well as control technology information changes due to detailed site-specific retrofit engineering studies conducted by Agrium prior to plant reactivation.

24. Section 9, Tables 9-2 to 9-4 present summary visibility modeling impact results for the respective NOx, SO2 and PM10 source/control option scenarios evaluated by Agrium. Each of the summary tables contains two columns relating to annual emission rates (tpy): one column reflects the 2002 actual annual emissions (i.e., the baseline emission rates), and one column reflects annual emission rates extrapolated from the maximum 24-hour actual emission rate used in the visibility impact modeling required per 40 CFR 51, Appendix Y. For sources of NOx (Table 9-2), the 2002 baseline emission rates were used to determine cost effectiveness, except for Primary Reform Unit 12. For Unit 12, Agrium utilized the lower modeled emission rate to determine cost effectiveness. Use of the lower annual emission rate results in a higher cost effectiveness value than when using the higher 2002 baseline emission rate. As such, should a detailed BART control analysis be prepared and submitted in the future, Agrium should provide justification for the use of the lower emission rate for Unit 12 cost effectiveness determination; or revise the cost effectiveness analysis to reflect the baseline emission rate.

By contrast to the aforementioned, the cost effectiveness values shown in Tables 9-3 (SO2 sources) and 9-4 (PM10 sources) reflect the use of the higher annual emission rate. While the higher emission rates generally reflect modeled emissions and not the 2002 baseline rates, the higher rates will nonetheless result in a relatively higher cost effectiveness values which are conservative.

25. Review of the CALPUFF input files indicates that BART eligible units 27 (Urea Prill Tower) and 35/36 (Granulators A/B) included source ammonia (NH_3) emissions modeled in CALPUFF. Discussion of such emissions from these units was not included in the approved protocol and, as such, Agrium should discuss such unit emissions with the Department before any future visibility modeling is conducted to support a revised BART analysis.

26. Review of the CALPUFF input files indicates that Urea Wharf Loading has been configured as an area source, as required by the Department in their protocol approval letter of April 18, 2008. However, Section 9 does not provide any information corresponding to horizontal and vertical dimensions input to CALPUFF for this source. As such, should a detailed BART control analysis be prepared and submitted in the future, Agrium should better explain the configuration and related CALPUFF input data for the Urea Wharf Loading.

27. Agrium did not submit the actual CALPOST modeling files with the August 2008 BART control analysis submittal; instead, only CALPOST summary results files have been provided by Agrium's modeling consultant, ERM. Should a detailed BART control analysis be prepared and submitted in the future, Agrium will need to submit all modeling files (including the CALPOST files) to confirm the applied modeling procedures.

28. Section 9.2 of Agrium's BART control analysis indicates the site specific sea salt concentrations for the Tuxedni Class I area were taken into account in the visibility modeling analysis. It is expected that this determination is consistent with the supplemental protocol information submitted to the Department by ERM, Agrium's consultant, on March 11, 2008. This information indicated that Agrium would utilize the "new" IMPROVE equation and methodology, which was approved by the Department on April 18, 2008. This notwithstanding, no detail on the application of this methodology is provided in the Agrium BART control analysis report, except for the limited mention in the final sentence of Section 9.2. Therefore, should a detailed BART control analysis be prepared and submitted in the future, Agrium should better explain the post-processing methods and version of the IMPROVE equation used to predict source visible impacts.

29. In general, Section 9 of Agrium's BART control analysis provides a very limited discussion on the modeling methods, model input and results post-processing. Review of the modeling methods has been accomplished through review of the modeling files. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should better explain the specific methods used to determine the visible impacts reflected in the summary results Table 9-1.

<u>Findings Associated with Section 10.0 of the Agrium BART Report (Summary and Conclusions)</u>

30. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should revise this section of the BART control analysis report to address any and all changes

identified in this findings report and independent findings by Agrium when conducting site-specific engineering evaluations pertaining to retrofit feasibility.

Findings Associated with Appendix A of the Agrium BART Report (RBLC Search Results)

31. Should a detailed BART control analysis be prepared and submitted in the future, Agrium should update and revise the search results for similar emission units, as identified on the U.S. EPA's RACT/BACT/LAER Clearinghouse.

APPENDIX B - RACT/BACT/LAER CLEARINGHOUSE (RBLC) SUMMARY

Findings Report
Agrium Kenai Nitrogen Operations (Agrium)
Best Available Retrofit Technology (BART) Evaluation

Prepared for

State of Alaska
Department of Environmental Conservation
Division of Air Quality

ADEC Contract No. 18-3001-17
NTP No. 18-3001-17-7A

Prepared by
Enviroplan Consulting
Edgewater Commons II
81 Two Bridges Road
Fairfield, NJ 07004

1. A search of the RBLC database found the following potentially applicable references that were not included in Agrium's RBLC review:

Facility Information			
RBLC ID:	OH-0267 (final)	**Date Determination Last Updated:**	08/15/2003
Corporate/Company Name:	THE SCOTTS COMPANY	**Permit Number:**	01-07992
Facility Name:	THE SCOTTS COMPANY	**Permit Date:**	06/01/2000 (actual)
Facility Contact:	GARY DAUGHERTY 937-644-0011	**FRS Number:**	110011696664
Facility Description:	FERTILIZER PLANT. THIS PERMIT WAS SUBMITTED TO INCREASE THE MAXIMUM ANNUAL HOURS OF OPERATION OF THE GRANULATION DRUM/PROCESS COOLER/RESIN REACTOR/MATERIAL HANDLING/ AND ASSOCIATED PACKAGING OPERATIONS TO 8760; AND TO INSTALL TWO NEW PRODUCTION LINES. THIS PERMIT WAS FIRST ISSUED ON 6/1/00, WAS APPEALED AND RE-ISSUED ON 12/27/01. THIS PERMIT INCLUDES AMMONIA EMISSION OF 1752 TONS.	**SIC Code:**	2875
Permit Type:	D: Both B (Add new process to existing facility) &C (Modify process at existing facility)	**NAICS:**	325314
EPA Region:	5	**COUNTRY:**	USA
Facility County:	UNION		
Facility State:	OH		
Facility ZIP Code:	43041		
Permit Issued By:	OHIO ENVIRONMENTAL PROTECTION AGENCY (Agency Name) MS. CHERYL SUTTMAN (Agency Contact) (614)644-3617 CHERYL.SUTTMAN@EPA.STATE.OH.US		
Other Agency Contact Info:	CHERYL E. SUTTMAN 122 S. FRONT ST. COLUMBUS, OH 43215 614-644-3617		
Other Permitting Information:	Fertilizer plant. This permit was submitted to increase the maximum annual hours of operation of the granulation drum/process cooler/resin reactor/material handling/ and associated packaging operations to 8760; and to install two new production lines. This permit was first issued on 6/1/00, was appealed and re-issued on 12/27/01. This permit includes ammonia emission of 1752 tons.		

Process/Pollutant Information

PROCESS NAME: GRANULATION DRUMS & PROCESS COOLERS - SYSTEM 2

Process Type: 61.012 (Fertilizer Production (except 61.009))

Primary Fuel: NATURAL GAS/LPG

Throughput: 60000.00 LB/H

Process Notes: Fabric filters control 0.005 grains/scf. Stack testing was conducted 5/19 & 5/20 1999 for the old units. Methods 5 and 201/201A shall be conducted to demonstrate compliance on the new units.

POLLUTANT NAME: Particulate Matter < 10 µ (PM10) **CAS Number:** PM

Emission Limit 1: 1.3600 LB/H

Emission Limit 2: 5.9000 T/YR

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (A) FABRIC FILTER, 0.005 GR/SCF. PULSE JET FABRIC CLEANING SYSTEM

Est. % Efficiency: 98.000

Compliance Verified: Y

Pollutant/Compliance Notes: Limits are for System 2 granulation drum. Stack testing Method 5 and Method 201 required, and already conducted on old units. Two of the units are new; cost analysis is for one of the new lines, each of which includes two resin reactors, granulation drum, process cooler, mill, screen, elevators, conveyors, and blending.

POLLUTANT **CAS Number:** 10102

NAME: Nitrogen Oxides (NO_x)

Emission Limit 1: 0.0900 LB/H

Emission Limit 2: 0.4000 T/YR

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: N/A

Other Applicable Requirements: SIP

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Y

Pollutant/Compliance Notes: Limit is for System 2 granulation system. Maximum fuel usage in each unit is 850 ft3/hr. All units restricted to natural gas or LPG. Stack testing if required, Method 7E.

POLLUTANT NAME: Particulate Matter (PM) **CAS Number:** PM

Emission Limit 1: 1.8300 LB/H

Emission Limit 2: 8.0200 T/YR

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (A) FABRIC FILTER, 0.005 GR/SCF. PULSE JET FABRIC CLEANING SYSTEM

Est. % Efficiency:

Compliance Verified: Y

Pollutant/Compliance Notes: Limits are for System 2 granulation drum. Stack testing Method 5 and Method 201 required, and already conducted on old units. Two of the units are new; cost analysis is for one of the new lines, each of which includes two resin reactors, granulation drum, process cooler, mill, screen, elevators, conveyors, and blending.

Process/Pollutant Information

PROCESS GRANULATION DRUMS & PROCESS COOLERS, (3)

NAME:

Process Type: 61.012 (Fertilizer Production (except 61.009))

Primary Fuel: NATURAL GAS/LPG

Throughput: 60000.00 LB/H

Process Notes: Fabric filters control 0.005 gr/scf. Stack testing was conducted 5/19 & 5/20 1999 for the older units. Method 5 and 201/201A shall be conducted to demonstrate compliance on the new units.

POLLUTANT NAME: Particulate Matter (PM) **CAS Number:** PM

Emission Limit 1: 3.0300 LB/H

Emission Limit 2: 13.3000 T/YR

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (A) FABRIC FILTER, 0.005 GR/SCF. PULSE JET FABRIC CLEANING SYSTEM.

Est. % Efficiency:

Compliance Verified: Y

Pollutant/Compliance Notes: Limits are for each of 3 granulation drums. Stack testing Method 5 and Method 201 required, and already conducted on old units. Two of the units are new; cost analysis is for one of the new lines, each of which includes two resin reactors, granulation drum, process cooler, mill, screen, conveyors, and blending.

POLLUTANT NAME: Particulate Matter < 10 µ (PM10) **CAS Number:** PM

Emission Limit 1: 3.0300 LB/H

Emission Limit 2: 13.3000 T/YR

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (A) FABRIC FILTER, 0.005 GR/SCF. PULSE JET FABRIC CLEANING SYSTEM

Est. % Efficiency:

Compliance Verified: Y

Pollutant/Compliance Notes: Limits are for each of 3 granulation drums. Stack testing Method 5 and Method 201 required, and already conducted on old units. Two of the units are new; cost analysis is for one of the new lines, each of which includes two resin reactors, granulation drum, process cooler, mill, screen, conveyors, and blending.

POLLUTANT NAME: Nitrogen Oxides (NO_x) **CAS Number:** 10102

Emission Limit 1: 0.0900 LB/H

Emission Limit 2: 0.4000 T/YR

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: N/A

Other Applicable Requirements: SIP

Control Method: (N)

Est. % Efficiency:

Compliance Verified: Y

Pollutant/Compliance Notes: Limit is for each granulation system. Maximum fuel usage is 850 ft3/hr. All units restricted to natural gas or LPG. Stack testing if required, Method 7E.

Response to Public Comments
Agrium, Kenai Nitrogen Operation Plant
Best Available Retrofit Technology (BART) Determination
Response to Comments
September 29, 2009

Prepared by: Rebecca Smith

The Alaska Department of Environmental Conservation (ADEC) proposed a preliminary BART determination for Agrium's Kenai Nitrogen Operations Plant on August 14, 2009. The BART eligible units at the source consist of five package boilers, five turbine/gensets, two primary reformers, two CO_2 compressor engines, a Urea Prill Tower, Granulators A/B, and materials handling at the Urea Loading Wharf. The Department accepted comments from August 14, 2009 until September 17, 2009. This document responds to comments received during the comment period.

The Department received written comments from the following by the September 17, 2009 deadline:

A) Sandra V. Silva, Chief, Brand of Air Quality, United State Department of the Interior, Fish and Wildlife Service (FWS)

Comments received by the Department on September 17, 2009, from FWS:

Commenter stated, "…Reducing the federally-enforceable emission limits for these units to zero, and specifying that a new Prevention of Significant Deterioration (PSD) permit application, review, and approval, would be needed prior to any future operation of the units, is acceptable to us for meeting the Regional Haze Rule obligations for these sources…."

Response from ADEC:

The Department acknowledges the comment from the FWS. The emission limits for the BART eligible units at Agrium will be set at zero for all pollutants of concern. Agrium will apply for any needed permits at such time as they want to restart the plant.

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF AIR QUALITY
AIR PERMITS PROGRAM

SEAN PARNELL, GOVERNOR
410 Willoughby Ave, Suite 303
PO Box 111800
Juneau, AK 99811-1800
PHONE: (907) 465-5100
FAX: (907) 465-5129
http://www.dec.state.ak.us

CERTIFIED MAIL: 7003 1680 0004 2909 1743
Return Receipt Requested

October 6, 2009

Mike Harper
Agrium US, Inc.
Kenai Nitrogen Operations Plant
P.O. Box 575
Kenai, AK 99611

Dear Mr. Harper:

Agrium, Kenai Nitrogen Operations Plant has completed the Alaska Department of Environmental Conservation's (Department) BART process under 18 AAC 50.260. Therefore, under 18 AAC 50.260(e)-(l), the Department is making the following final BART determination, due to the current shutdown status of the Kenai Nitrogen Operations Plant:

- **Nitrogen Oxides (NOx) Control at Agrium:**
  - Nitrous Oxides (NOx) emissions control will be zero emissions from BART eligible units.
- **Sulfur Dioxide (SO_2) Control at Agrium:**
  - Sulfur Dioxide (SO_2) emissions control will be zero emissions from BART eligible units.
- **Particulate Control at Agrium:**
  - Particulate Matter (PM) emissions control be zero emissions from BART eligible units.

Additionally, prior to restarting the Kenai Nitrogen Plant, Agrium will apply for all necessary permits.

The Department public noticed a preliminary Best Available Retrofit Technology (BART) determination for the Kenai Nitrogen Operations Plant from August 14 to September 17, 2009. The Department received one comment supportive of the preliminary determination from the U.S. Fish and Wildlife Service (USFWS). Please see the enclosed Response to Comments document for the Department's response.

The Department must include all BART determinations in the Regional Haze SIP, per Section 169A of the Clean Air Act. As part of the overall Regional Haze State Implementation Plan (SIP), please note that the Department's decision is subject additional to public comment and approval by the U.S. Environmental Protection Agency (EPA).

Box 111800, Juneau, Alaska 99811-1800, within 30 days of the permit decision. If a hearing is not requested within 30 days, the right to appeal is waived.

Future Regulatory Actions related to this Decision:
The Department must include all BART determinations in its Regional Haze State Implementation Plan (SIP) per Section 169A of the Clean Air Act. The Department must submit the Regional Haze SIP proposal to Federal Land Managers (FLMs) for comment, and then provide public comment period. After the comment period, the Department will submit the final SIP to the U.S. Environmental Protection Agency (EPA) for review and approval. While not expected, any adverse comments from the public or EPA may be cause for reopening the Department's determination.

Sincerely,

John F. Kuterbach
Program Manager

Enclosures: Findings Report; USFWS Comments; Department Response to Comments

cc: Lisa Parker, Agrium US, Inc.
Sandra Silva, U.S. Fish and Wildlife Service
Steve Body, EPA, Region 10 (via e-mail)
Herman Wong, EPA, Region 10 (via e-mail)
Tim Allen, U.S. Fish and Wildlife Service (via e-mail)
Bud Rice, National Park Service (via e-mail)
Bruce Polkowsky, National Park Service (via e-mail)
John Notar, U.S. Fish and Wildlife Service (via e-mail)
John Vimont, National Park Service (via e-mail)
Andrea Blakesley, National Park Service, Denali (via e-mail)
Ann Mebane, U.S. Forest Service (via e-mail)
David Mott, U.S. Forest Service, Alaska Region (via e-mail)
Mike Hirtler, Enviroplan Consulting (via e-mail)
Tom Turner, ADEC/APP (via e-mail)
Alan Schuler, ADEC/APP (via e-mail)
Cynthia Wiliams, ADEC/ANP&MS (via e-mail)
Rebecca Smith, ADEC/APP (via e-mail)

BEFORE THE STATE OF ALASKA

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

COMPLIANCE ORDER BY CONSENT

Whereas the State of Alaska, Department of Environmental Conservation ("ADEC"), and ConocoPhillips Alaska Natural Gas Corporation desire to resolve and settle a disputed matter and to avoid the uncertainty and expense of formal enforcement proceedings, it is hereby agreed as follows:

I. JURISDICTION

1. This Compliance Order by Consent (hereinafter "Order") is entered into under the authority of the Alaska Department of Environmental Conservation under AS 44.46.020, AS 46.03.020, AS 46.03.760(e), AS 46.03.765, AS 46.03.850, and 18 AAC 95.160, and the settlement authority of the Attorney General under AS 44.23.020.

II. BACKGROUND

2. The Kenai LNG Corporation is the owner, and ConocoPhillips Alaska Natural Gas Corporation ("CPANG" or "ConocoPhillips") is the operator, of the Liquefied Natural Gas facility at Kenai, Alaska ("Kenai LNG Plant" or "Plant"). The physical address of the Kenai LNG Plant is Mile 21.5 Kenai Spur Highway Kenai, Alaska, and it receives mail at P.O. Drawer 66, Kenai, Alaska 99611.

3. ConocoPhillips operates equipment identified in the Emissions Unit Inventory attached as Exhibit A and incorporated in this Order by this reference ("the Equipment"). The Equipment was installed during the timeframe that would make the emissions units a "BART eligible facility" if the Plant is on a list of source categories identified as subject to the federal Regional Haze program. *See* 40 C.F.R. Part 51, Appendix Y.

4. In 2007, ConocoPhillips and ADEC exchanged correspondence and had several meetings concerning whether the Equipment should be classified as a "fuel conversion plant" thus making the Equipment a "BART eligible facility" subject to the Regional Haze program and its requirement for

use of Best Available Retrofit Technology ("BART"). ConocoPhillips has contested ADEC's assertion that the Plant is subject to the Regional Haze program, and specifically denies that the Kenai LNG Plant is a "fuel conversion plant."

5. By letter dated January 4, 2008, ADEC's air permits program manager notified ConocoPhillips that the Plant was subject to the Regional Haze program.

6. Rather than dispute the classification, ConocoPhillips attempted to exempt the Equipment from BART requirements through modeling. However, the modeling revealed that visibility impacts from the equipment exceed the regulatory threshold for "caus[ing] or contribut[ing] to impairment of visibility." *See* 18 AAC 50.260(q)(4).

7. ConocoPhillips prepared a BART Analysis and by agreement presented it to ADEC for discussion only, and not for use by ADEC as the basis for a formal BART determination without the approval of ConocoPhillips. ADEC reviewed the BART Analysis and concluded that it used correct methodology and that it addressed the appropriate control technologies needed for a BART analysis. ADEC provided a preliminary, nonbinding statement that the emission limits proposed for this Order are at least as stringent as what could be expected from a formal BART analysis.

8. ConocoPhillips had also proposed an Owner Requested Limit ("ORL") to reduce emissions from the Equipment to a level that would be lower than the regulatory threshold described in section 6 above. In its ORL application, ConocoPhillips reserved its rights to contest the classification of the Plant as a "fuel conversion plant."

9. ConocoPhillips and ADEC agree that this Order should operate in lieu of the ORL and BART analysis to avoid classification of the Equipment as a "fuel conversion plant" subject to the Regional Haze Program yet would restrict emissions from the Equipment to a level which would qualify for an exemption from BART requirements.

III. AGREEMENT

10. In order to fully resolve the current dispute over whether the Kenai LNG Plant is a "fuel conversion plant" subject to the Regional Haze Program, ConocoPhillips and ADEC agree that:

10.1. ConocoPhillips will limit emissions from the Equipment after December 31, 2013 in accordance with the Emissions Limits, Monitoring, Recordkeeping and Reporting ("ELMR&R") requirements attached to this Order as Exhibit B and incorporated herein by this reference.

10.2. The requirements of the ELMR&R shall be "applicable requirements" to be incorporated into the Title V air operating permit for the plant in accordance with ADEC regulations.

10.3. This Order may be relied upon by ADEC to satisfy the obligations of the State of Alaska under the federal Regional Haze program and may be referenced in the State Implementation Plan ("SIP") submitted to U.S. Environmental Protection Agency ("EPA") for that program. As long as this Order remains in effect, ADEC will not impose any BART obligations on the Equipment, other than the obligations under this Order.

10.4. In the event that EPA disapproves or conditionally approves this Order as a means for Alaska to implement the Regional Haze program with respect to the Kenai LNG Plant, ConocoPhillips may at its sole discretion by written notice to ADEC terminate this Order and challenge EPA's and/or ADEC's classification of the Plant as a "fuel conversion plant" or assert other claims or defenses.

10.5. This Order does not affect the right and ability of ConocoPhillips to seek review of any future decision classifying the Plant as a "fuel conversion plant" under the Clean Air Act or State of Alaska laws and regulations. Nor does it affect the right and ability of ADEC to assert that the Plant is a "fuel conversion plant" for purposes other than the Regional Haze Program.

10.6. This Order does not affect ConocoPhillips' ability to use any emissions reductions as creditable emissions decreases allowed under new source review or construction permitting laws and regulations, federal or state, in effect at the time of the use of the credit.

10.7. Until December 31, 2018, ADEC will not impose any other Regional Haze obligations on the Equipment, including obligations related to Reasonable Progress Goals, other than the obligations under this Order. After December 31, 2018, ADEC is not precluded from requiring additional controls in future Regional Haze SIP updates should they be necessary to meet Reasonable Progress Goals.

10.8. This Order applies only to the Equipment, and does not affect or apply to other equipment that replaces the Equipment. This Order does not affect the applicability of any requirements related to replacement equipment.

IV. COSTS INCURRED BY CONOCOPHILLIPS

11. All costs incurred by ConocoPhillips in carrying out this Order shall be borne by ConocoPhillips.

V. DEPARTMENT ORDER

12. This Order constitutes a lawful Order of ADEC for the purposes of AS 46.03.760, AS 46.03.765, AS 46.03.790, AS 46.03.850, AS 46.14.120(c), 18 AAC 95.160 and for all other purposes. Kenai LNG Corp. and ConocoPhillips shall not institute any action challenging the validity of this Order or the authority of ADEC to enforce this Order, nor shall Kenai LNG Corp. and ConocoPhillips controvert or challenge, in any subsequent proceedings initiated by the State of Alaska, the validity of this Order or the authority of ADEC to issue and enforce this Order.

VI. INDEMNIFICATION

13. Kenai LNG Corp. and ConocoPhillips shall hold the State of Alaska and its representatives, agents, and employees harmless and indemnify and defend the State of Alaska against all claims, liabilities, losses, damages, and costs awarded or incurred, including attorney fees, and against all

actions and claims, whether wrongfully brought or not, including but not limited to third-party claims (i.e., excluding tort claims made by the State of Alaska and/or any State of Alaska agency or entity) for injury to or death of persons and loss of or damage to property arising out of or in any manner connected with the obligations of Kenai LNG Corp. or ConocoPhillips pursuant to paragraph 10 of this Order, except for any claims arising out of the sole negligence of the State.

VII. PARTIES' REPRESENTATIVES

14. The undersigned representatives certify that they are fully authorized to enter into the terms and conditions of this Order and to bind the entity they represent to this Order.

VIII. MODIFICATIONS

15. ADEC may, with ConocoPhillips's written consent, modify this Order.

IX. STATE NOT A PARTY

16. The State of Alaska shall not be held as a party to any contract entered into by Kenai LNG Corp. or ConocoPhillips related to activities conducted pursuant to this Order.

X. RESERVATION OF RIGHTS

17. The requirements, duties, and obligations set forth in this Order are in addition to any requirements, duties, or obligations contained in any Permit which ADEC has issued or may issue to ConocoPhillips and are in addition to any requirements, duties, or obligations imposed by State, local, or federal law. Other than as expressly provided herein, this Order does not relieve ConocoPhillips from the duty to comply with requirements contained in any such Permit or with any State, local or federal law.

XI. COVENANT NOT TO SUE

18. Subject to the provisions of Section X (Reservation of Rights), and to paragraph 10.7, and provided Kenai LNG Corp. and ConocoPhillips comply with the terms of this Order to the reasonable satisfaction of ADEC, ADEC shall not institute any further action or proceeding against Kenai LNG Corp. or ConocoPhillips with respect to compliance with Regional Haze or BART requirements at the Kenai LNG Plant. However, nothing herein shall be construed as limiting ADEC's right to seek

damages, penalties, and fines for violation of the terms and conditions of this Order.

XII. DISPUTE RESOLUTION

19. The parties agree to make reasonable efforts to informally resolve all disputes at the staff level. If any dispute is still unable to be resolved, ConocoPhillips may make a written request for the Commissioner or the Commissioner's delegate to resolve the dispute. The pendency of any dispute pursuant to this paragraph shall not affect Respondent's responsibility for timely performance of the requirements of this Order. The Commissioner or the Commissioner's delegate will issue a final determination in writing. The written decision will be final for purposes of judicial review pursuant to Alaska Rule of Appellate Procedure 602(a)(2). The determination of the Commissioner or the Commissioner's delegate will remain in effect pending resolution of any judicial appeal unless a stay is sought and granted by the court on appeal.

XIII. JURISDICTION AND VENUE

20. Any judicial action brought by either party to enforce or adjudicate any provision of the Order shall be brought in the Superior Court for the State of Alaska, Third Judicial District at Anchorage.

XIV. SEVERABILITY

21. It is the intent of the parties hereto that the clauses of this Order are severable and should any part of it be declared by a court of law to be invalid and unenforceable, the other clauses shall remain in full force and effect.

XV. NO WAIVER

22. A failure to enforce any provision of this Order in no way implies a waiver of ADEC's right to insist upon strict performance of the same or other provision in the future.

XVI. NO WARRANTY OF PERMIT ISSUANCE BY THE DEPARTMENT

23. Nothing in this Order is intended or should be construed as a representation or assurance that any future Permits required for operation of the Plant will be issued by ADEC, or that the lawful terms of any such Permits, if issued, shall be consistent with the provisions of this Order.

XVII. EFFECTIVE DATE

24. The effective date of this Order shall be the date of the last signature when the Order is signed by authorized representatives of ConocoPhillips, ADEC, and the Alaska Attorney General's Office.

XVIII. SUCCESSORS

25. This Order shall be binding upon Kenai LNG Corp. and ConocoPhillips, its agents, successors, and assigns (including any lessee or grantee of the Plant), and upon all persons, contractors and consultants acting on behalf of Kenai LNG Corp. or ConocoPhillips.

26. Unless this Order has terminated as provided in Paragraph 27 below, Kenai LNG Corp. and ConocoPhillips shall incorporate a copy of this Order into any conveyance of their interest in the Plant and into any lease or management agreement respecting the ownership or operation of the Plant, and shall require in any such conveyance, lease or agreement that the grantee, lessee or manager shall comply with all of the requirements of this Order.

XIX. TERMINATION

27. This Order shall terminate:

27.1. On the date ConocoPhillips notifies ADEC that it is terminating the Order due to EPA's disapproval or conditional approval of the Order as a Regional Haze and BART compliance strategy for the Kenai LNG Plant;

27.2. On the date that none of Emission Unit IDs 1 through 6 remain in service because they have been permanently decommissioned;

27.3. Upon the effective date of a new order that by its terms replaces this Order.

DATED: August 4, 2009

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

By: Alice Edwards
Acting Director of Air Quality

DATED: August 7, 2009

DANIEL S. SULLIVAN
ATTORNEY GENERAL

By: ______________________

Cameron Leonard
Senior Assistant Attorney General

DATED: July 21, 2009

Kenai LNG Corporation

By: ______________________

Erec Isaacson
Vice President

I, Erec Isaacson, hereby certify that I hold the position of Vice President and that I am a responsible official for the Kenai LNG Plant and that I have the authority to enter into agreements on behalf of the Kenai LNG Corp. and to otherwise legally bind the Kenai LNG Corp. I hereby acknowledge that I have freely and voluntarily entered into this agreement with the State of Alaska on behalf of the Kenai LNG Corp.

SUBSCRIBED AND SWORN to before me this 21 day of July, 2009.

CAROL KELLY
My Commission Expires
NOTARY PUBLIC
Aug. 16, 2012
STATE OF ALASKA

Carol Kelly
Notary Public, State of Alaska
My commission expires: Aug. 16, 2012

DATED: July 21, 2009

ConocoPhillips Alaska Natural Gas Corporation

By: Daniel M. Clark
Daniel M. Clark
Vice President

I, Daniel M. Clark, hereby certify that I hold the position of Vice President and that I am a responsible official for the Kenai LNG Plant and that I have the authority to enter into agreements on behalf of ConocoPhillips Alaska Natural Gas Corporation and to otherwise legally bind ConocoPhillips Alaska Natural Gas Corporation. I hereby acknowledge that I have freely and voluntarily entered into this agreement with the State of Alaska on behalf of ConocoPhillips Alaska Natural Gas Corporation.

SUBSCRIBED AND SWORN to before me this 21 day of July, 2009.

CAROL KELLY
My Commission Expires
NOTARY PUBLIC
Aug. 16, 2012
STATE OF ALASKA

Carol Kelly
Notary Public, State of Alaska
My commission expires: Aug. 16, 2012

EXHIBIT A TO COBC # ______________________

Emission Unit Inventory

Unit ID	Source Name	Source Description	Fuel	Rating/Size	Install Date
1	General Electric Frame 5/1 Model LA	Compressor Drive – Propane Cycle #151	Natural Gas	155.6 MMBtu/hr	1969
2	General Electric Frame 5/1 Model LA	Compressor Drive – Propane Cycle #152	Natural Gas	155.6 MMBtu/hr	1969
3	General Electric Frame 5/1 Model LA	Compressor Drive – Ethylene Cycle #251	Natural Gas	233.9 MMBtu/hr	1969
4	General Electric Frame 5/1 Model LA	Compressor Drive – Ethylene Cycle #252	Natural Gas	228.7 MMBtu/hr	1969
5	General Electric Frame 5/1 Model LA	Compressor Drive – Methane Cycle #351	Natural Gas	156.4 MMBtu/hr	1969
6	General Electric Frame 5/1 Model LA	Compressor Drive – Methane Cycle #352	Natural Gas	156.4 MMBtu/hr	1969
8	Erie City 9M	Boiler No. 501	Natural Gas	47 MMBtu/hr	1969
9	Erie City 9M	Boiler No. 502	Natural Gas	47 MMBtu/hr	1969
10	Erie City 9M	Boiler No. 511	Natural Gas	47 MMBtu/hr	1969
11	Caterpillar D-379	Emergency Generator	Diesel	350 kW	1969
15	Ground Flare	Flare	Natural Gas	148 MMscf/day	1969

EXHIBIT B TO COBC # _______________________

Emissions Limits, Monitoring, Recordkeeping and Reporting Requirements

ConocoPhillips shall:

1. After December 31, 2013, limit the total combined calendar day operating hours of Emission Unit (EU) IDs 1 through 6 to a maximum of 78 hours per day, or to an alternative limit established under paragraph 2.c.[1]
    a. Monitor and record as follows:
        i. Maintain daily records of operating hours for each of EU IDs 1 through 6.
        ii. Keep a record of the maximum potential daily NO_x emission rate from EU IDs 1 through 6 based on condition 2.
2. No later than December 31, 2013 and at least once every 12 months thereafter,
    a. Conduct NO_x source tests to obtain NO_x emission rates in lb/hr on:
        i. either EU IDs 1 or 2;
        ii. either EU IDs 3 or 4; and
        iii. either EU IDs 5 or 6.
    b. If the NO_x emission rates from the most recent source test are such that the 78 hour per day limit in condition 1 above is insufficient to ensure NO_x emissions remain at or below the maximum daily rate of 5,467 lbs,

[1] This operating hour limit is based on a maximum potential daily NO_x emission rate from EU IDs 1 through 6 of 5,467 lb/day derived from modeling. The 5,467 lb/day value is not an enforceable limit.

permittee shall perform the actions under 2.b.i and 2.b.ii below or under paragraph 2.c:

i. Make repairs, adjustments, or changes necessary to bring NO_x emission rates back down to level so that 78 hours is sufficient to ensure emissions remain at or below 5,467 lbs/day; and

ii. Repeat testing within 90 days of completing the efforts under 2b.i. to confirm emission rates support the use of 78 hours as the daily limit.

c. If actions are required under 2.b and those performed under 2.b.i and 2.b.ii and are not performed or are unsuccessful, obtain ADEC approval of a new maximum hourly limit to replace the limit in paragraph 1 above and apply during future calendar years until revised by operation of this paragraph. The new maximum hourly limit shall be based on a maximum potential daily NO_x emission rate from EU IDs 1 through 6 of 5,467 lb/day.

3. The Permittee shall conduct source testing:

a. At a point or points that characterize the actual discharge into the ambient air;

b. At the maximum rated burning or operating capacity of the unit or another rate determined by the Department to characterize the actual discharge into the ambient air; and

c. In accordance with the methods and procedures specified in 40 C.F.R. 60, Appendix A-7, Method 20.

4. Burn only fuel gas with a hydrogen sulfide (H_2S) content equal to or less than 3.0 parts per million volume (ppmv) in EU IDs 1 through 6.
5. Monitor and record the H_2S content of the fuel gas combusted in EU IDs 1 through 6 at least once each calendar month, using the length-of-stain detector tube technique as set out in ASTM D 4810-88, ASTM D 4913-89, or GP 2317-86, or any other measurement methodology approved by the Department.

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF AIR QUALITY

SARAH PALIN, GOVERNOR

555 Cordova Street
Anchorage, AK 99501
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CERTIFIED MAIL: 7006 3450 0003 8328 8939
Return Receipt Requested
November 23, 2007

Mr. Bradley C. Thomas
Senior Environmental Engineer
Alyeska Pipeline Service Company
P.O. Box 196660
Anchorage, AK 99519-6660

Subject: Approval of BART Exemption Analysis for Valdez Marine Terminal

Dear Mr. Thomas:

The Alaska Department of Environmental Conservation (Department) is approving the Best Available Retrofit Technology (BART) exemption analysis submitted by Alyeska Pipeline Service Company (APSC) on November 9, 2007 for the Valdez Marine Terminal (VMT). The analysis adequately shows that the maximum 24-hour change in visibility at the Denali National Park and Tuxedni Wilderness Class I areas due to the VMT BART-eligible sources are less than the 0.5 deciview threshold. APSC has therefore demonstrated that VMT is not subject to BART and as such, is *not* required to submit a BART emission control analysis.

Please note that the Department's decision is subject to public comment and approval by the U.S. Environmental Protection Agency (EPA). The Department must include all BART decisions in the regional haze component of the State Implementation Plan (SIP), per Section 169A of the Clean Air Act. The Department must also provide public notice for the regional haze SIP proposal, per state and federal requirements. Once the comment period is completed, the Department will submit the proposal, or a modified version thereof, to EPA for review and approval. While the Department does not expect adverse comments from the public or EPA, receipt of such may be cause for reopening the VMT decision and asking APSC to revise the analysis (if warranted).

For public record purposes, the key aspects of APSC's analysis are:

- use of maximum actual daily emissions rather than the potential emissions used in the Western Regional Air Partners (WRAP) analysis;
- use of corrected stack parameters (see following discussion); and

- consistency with WRAP's modeling *protocol* (see following discussion), including;
  - the same meteorological data and CALPUFF dispersion model, and
  - use of the maximum change in visibility rather than the 98th percentile change in visibility.

APSC corrected several stack parameters (exit velocities and temperatures) to be consistent with previous modeling submittals. In reviewing the submittal, the Department found that we had made a number of data entry errors in the stack parameter spreadsheet that we provided WRAP. Therefore, APSC's correction of these errors is appropriate. APSC also used the actual base elevation for each unit rather than the generic base elevation used by WRAP for all units. The stack parameter changes are listed in the enclosed table.

APSC noted that WRAP changed three of the CALPUFF settings (CDIV, MXSAM, SL2PF) from the EPA default values presented in the protocol. WRAP did not note this change in their summary report or provide any explanation as to why they deviated from the approved protocol. APSC discussed this issue with the Department, EPA Region 10 and the Federal Land Managers during a June 4, 2007 teleconference, and with unanimous verbal approval, changed the settings back to the EPA default values.

APSC found that the maximum change in visibility impacts at Denali are 0.080 deciviews and the maximum change in visibility impacts at Tuxedni are 0.065 deciviews. Both impacts are well below the 0.5 deciview threshold.

Sincerely,

Tom Chapple
Director
Division of Air Quality

Enclosure: Stack Parameter Comparison

cc: John Kuterbach, ADEC/APP, Juneau
Alice Edwards, ADEC/ANMS, Juneau
Tom Turner, ADEC/APP, Anchorage
Alan Schuler, ADEC/APP, Juneau

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Stack Parameter Comparison
(Base Elevation, Exhaust Temperature, Exit Velocity)

Unit	Rating	Base Elevation (m)		Temperature (K)		Exit Velocity (m/s)	
		WRAP Run	APSC Run	WRAP Run	APSC Run	WRAP Run	APSC Run
Incinerator	400 MMBtu/hr	283.5	106.7	500	1033	9.14	54.0
Boiler	242 MMBtu/hr	283.5	106.7	500	500	9.14	13.5
Generator	1050 kW	283.5	50.0	500	500	0.00	0.001
FW Pump	763 hp	283.5	80.0	500	500	0.00	0.001
FW Pump	864 hp	283.5	80.0	500	500	0.00	0.001

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION
DIVISION OF AIR QUALITY
AIR PERMITS PROGRAM

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May 7, 2007

Gregory H. Arthur, P.E.
Manager of Environmental Engineering
Chugach Electric Association, Inc.
5601 Electron Dr.
P.O. Box 196300
Anchorage AK 99519-6300

Dear Mr. Arthur:

Thank you for your feedback on the Department of Environmental Conservation's (DEC) preliminary list of BART-eligible emission units. We received and reviewed your response. We have consulted with EPA about the status of Chugach's emission units with regard to BART-eligibility. They have concurred that Chugach Beluga Power Plant only became a "steam electric plant" after the BART timeframe. Therefore, the Beluga Power Plant is not a BART-eligible source, and Chugach will not need to participate further in the BART process.

Please feel free to contact me at (907) 269-8123 or Rebecca Smith at (907) 465-5121 if you would like to discuss this further.

Thank you for your prompt response.

Sincerely,

Tom Turner, Tech Services Manager

CC: Tim Allen, USFWS
Bruce Polkowsky, NPS
Steve Body, EPA, Region 10
John Kuterbach, DEC/AQ, Juneau AK

STATE OF ALASKA

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May 7, 2007

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Please feel free to contact me at (907) 269-8123 or Rebecca Smith at (907) 465-5121 if you would like to discuss this further.

Thank you for your prompt response.

Sincerely,

Tom Turner, Tech Services Manager

CC: Tim Allen, USFWS
Bruce Polkowsky, NPS
Steve Body, EPA, Region 10
John Kuterbach, DEC/AQ, Juneau AK

United States Department of the Interior

FISH AND WILDLIFE SERVICE
National Wildlife Refuge System
Branch of Air Quality
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2017

IN REPLY REFER TO:

FWS/ANWS-AR-AQ

September 17, 2009

Rebecca Smith
Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
P. O. Box 111800
Juneau, Alaska 99811-1800

The U. S. Fish and Wildlife Service reviewed the State of Alaska, Department of Environmental Conservation's (ADEC) Best Available Retrofit Technology (BART) determination for the Kenai Nitrogen Operations Plant. ADEC proposed that BART emission limits for nitrogen oxides, sulfur dioxide and particulate matter for BART eligible units at the Kenai Nitrogen Operations Plant be set at zero, since it is not currently operating. Reducing the federally-enforceable emission limits for these units to zero, and specifying that a new Prevention of Significant Deterioration (PSD) permit application, review, and approval, would be needed prior to any future operation of the units, is acceptable to us for meeting the Regional Haze Rule obligations for these sources.

We appreciate the opportunity to comment on this proposed action. If you have any questions, please contact Tim Allen of this office at (303) 914-3802.

Sincerely,

Sandra V. Silva

Sandra V. Silva, Chief
Branch of Air Quality

cc:

Mahbubul Islam, Manager
State and Tribal Air Programs Unit
US EPA Region 10
1200 6th Avenue
Seattle, Washington 98101

TAKE PRIDE IN AMERICA

FISH AND WILDLIFE SERVICE
AIR QUALITY BRANCH

FACSIMILE COVER SHEET

Date: Sept. 17, 2009 *Telephone: (303) 914-*3808
Fax: (303) 969-5444

To: Rebecca Smith, Environmental Program Specialist, Air Permit Program, Alaska Dept. of Env. Conservation
FAX: 907 465-5129

From: Meredith Bond

Subject: Comment regarding proposed permit for BART requirements at Kenai Nitrogen Operations Plant.

Rebecca,
Pls. find Fish & Wildlife Service, Branch of Air Quality's, comment in attached letter. Hard copy original will follow via regular mail.
MB.

Number of Pages (including this cover sheet): 2

7333 W. Jefferson, Suite 375, Lakewood, CO 80235