MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Permitting and Compliance Division
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Southern Montana Electric Generation and Transmission Cooperative, Inc.
Highwood Generating Station Natural Gas Plant
Sections 24 and 25, Township 21 North, Range 5 East, Cascade County, Montana
3521 Gabel Road, Suite 5
Billings MT 59102

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	XX		
Ambient Monitoring Required		XX	
COMS Required		XX	
CEMS Required	XX		
Schedule of Compliance Required		XX	
Annual Compliance Certification and Semiannual Reporting Required	XX		
Monthly Reporting Required		XX	
Quarterly Reporting Required		XX	
Applicable Air Quality Programs			
ARM Subchapter 7 – Montana Air Quality Permit (MAQP)	XX		MAQP #4429-00
New Source Performance Standards (NSPS)	XX		Subpart KKKK and Subpart IIII
National Emission Standards for Hazardous Air Pollutants (NESHAPS)		XX	See MACTS
Maximum Achievable Control Technology (MACT)	XX		Subpart ZZZZ
Major New Source Review (NSR) – includes Prevention of Significant Deterioration (PSD) and/or Non-attainment Area (NAA) NSR	XX		Major for CO and NO_X
Risk Management Plan Required (RMP)		XX	
Acid Rain Title IV	XX		
Compliance Assurance Monitoring (CAM)		XX	
State Implementation Plan (SIP)	XX		As applicable

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emissions units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit. Conclusions in this document are based on information provided in the original application submitted by Southern Montana Electric Generation and Transmission Cooperative, Inc. (SME) on received on April 24, 2009, and additional information received relevant to that permitting action.

B. Facility Location

The facility is located approximately 8 miles east of Great Falls, Montana. The legal description of the site is Sections 24 and 25, Township 21 North, Range 5 East, Cascade County, Montana; the Highwood Generating Station Natural Gas Plant (HGS gas plant) is primarily located in Section 25. The approximate universal transverse Mercator (UTM) coordinates are Zone 12, Easting 497 kilometers (km), and Northing 5,266 km (North American Datum of 1927). The approximate latitude/longitude coordinates are latitude 47.55 decimal degrees and longitude -111.03 decimal degrees. The site elevation is approximately 3,310 feet.

C. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
XX		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	XX	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	XX	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	XX	4. Does the action deprive the owner of all economically viable uses of the property?
	XX	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	XX	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	XX	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	XX	7a. Is the impact of government action direct, peculiar, and significant?
	XX	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	XX	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	XX	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

D. Compliance Designation

The Department conducted a full compliance evaluation covering the period from issuance of MAQP #4429-00 on November 2, 2009, through May 19, 2011. During the two-year compliance review period, based upon the information gathered during the facility inspection, the observations made at the facility, and the review of facility records, SME appeared to have been in compliance with regards to the conditions and limitations of MAQP #4429-00, with exception of a late 2010 emissions inventory report.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

The facility will consist of two combustion turbine generators each with duct firing and a heat recovery steam generator (HRSG), a third steam turbine generator that utilizes heat output from the two combustion turbines, three grouped cooling towers, miscellaneous building heaters, a black-start emergency generator, and an emergency fire pump.

The proposed generating units for the HGS gas plant are two General Electric LM6000PF Dry Low Emissions (DLE) combustion turbines (DLE is the turbine manufacturer term for Dry Low NOx burners or DLN). The LM6000PF is a simple cycle combustion unit containing one aeroderivative combustion turbine and a single shaft-driven electric generator. Within each combustion turbine, combustion air is compressed and mixed with fuel, then fired in the combustor to produce compressed hot combustion gases. Expansion of these gases in the turbine rotates the turbine shaft, which turns a generator to produce electricity. Each of the two LM6000PF generating units is rated at approximately 43 MW at 100% load at 54.7 degrees Fahrenheit (°F) ambient temperature. Including the electricity generated from the heat recovery steam generators and steam turbine, the plant gross total is approximately 120 MW. Pipeline quality natural gas is the selected operations and startup fuel.

In addition to the power block, other tanks and machinery will be installed at this facility. A black-start emergency generator and fire pump will be installed, both diesel-powered. Aqueous ammonia will be stored in above-ground horizontal tanks for use in the Selective Catalytic Reduction (SCR) air pollution control device that was selected as best available control technology (BACT) for control of nitrogen oxides (NO_x) emissions during combined cycle operation.

Cooling towers will be used to dissipate the heat from the condenser by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling towers. The proposed cooling towers will be an induced, counter flow draft design equipped with drift eliminators. The average make-up water rate for the proposed cooling towers will be approximately 394 gallons per minute (gpm).

SME plans to construct the facility in two phases. Phase I includes the construction and operation of two natural gas-fired turbines to operate in simple cycle mode. In Phase II, SME will add duct burners, heat recovery equipment and a steam-driven turbine to make the facility a combined cycle system. During initial Phase I service (defined as operations before the HRSG and steam plant are installed), permit conditions limit the hours of simple cycle operation to 3,200 hours per year, including startup and shutdown time. During Phase II, following the installation of the steam plant, the simple cycle hours of operation will maintain a limit of 3,200 hours per year, and combined cycle operation will include a limit on startup and shutdown time. However, Phase II will not limit steady state operation in combined cycle mode. SME proposed to permit the facility for continuous combined cycle operation of both generating units to service all eventualities including an emergency electrical power demand.

For simple cycle operation, proper design and operation, and the use of pipeline quality natural gas, will control emissions of sulfur dioxide (SO_2), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). SME is required by permit to combust only pipeline quality natural gas, which will result in reduced SO_2 and $PM_{10}/PM_{2.5}$ emissions. DLN will control NO_x emissions. The 3,200 hour annual limit on operations will also limit emissions while in simple cycle mode.

For combined cycle operation, SCR will control post-combustion exhaust emissions of NO_x, and catalytic oxidation will control post-combustion exhaust emissions of carbon monoxide (CO) and volatile organic compounds (VOC). DLN burners will also contribute to reduced CO and VOC emissions by leaning out the air fuel mixture. Proper design and operation, and the use of pipeline quality natural gas, will control emissions of SO_2 and $PM_{10}/PM_{2.5}$. Permit conditions limit the number of hours per year that the facility is in startup or shutdown mode during combined cycle operation.

B. Emission Units and Pollution Control Device Identification

Emissions Unit ID	Description	Pollution Control Device/Practice
EU001	General Electric LM6000PF DLE Combustion Turbine	Catalytic Oxidizer, Selective Catalytic Reduction
EU002	General Electric LM6000PF DLE Combustion Turbine	Catalytic Oxidizer, Selective Catalytic Reduction
EU003	2,206 bhp diesel-fired emergency generator engine	500 hr/yr
EU004	343 bhp fire pump engine	500 hr/yr
EU005	Fugitive Dust Emissions	Water and/or chemical dust suppression

C. Categorically Insignificant Sources/Activities

Emissions Unit ID	Description
IEU01	Building Heater: Turbine Enclosure
IEU02	Building Heater: Admin/Maintenance/Electricals/STG Building
IEU03	Building Heater: Water Treatment Building
IEU04	Building Heater: Warehouse
IEU05	Building Heater: Water Pumphouse
IEU06	Building Heater: Fuel Gas Compressor Building
IEU07	Building Heater: CEMS Enclosures (2 each)

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

The generating units for the HGS gas plant are two General Electric LM6000PF Dry Low Emissions (DLE) combustion turbines.

For simple cycle operation, proper design and operation, and the use of pipeline quality natural gas, will control emissions of SO_2, PM, PM_{10}, and $PM_{2.5}$. SME is required by permit to combust only pipeline quality natural gas, which will result in reduced SO_2 and $PM_{10}/PM_{2.5}$ emissions. Dry Low NO_X Burners will control NO_X emissions. The 3,200 hour annual limit on operations will also limit emissions while in simple cycle mode.

For combined cycle operation, Selective Catalytic Reduction will control post-combustion exhaust emissions of NO_X, and catalytic oxidation will control post-combustion exhaust emissions of CO and VOC. Dry Low NO_X burners will also contribute to reduced CO and VOC emissions by leaning out the air fuel mixture. Proper design and operation, and the use of pipeline quality natural gas, will control emissions of SO_2 and $PM_{10}/PM_{2.5}$. Permit conditions limit the number of hours per year that the facility is in startup or shutdown mode during combined cycle operation.

The facility is also Subject to New Source Performance Standards (NSPS), 40 CFR 60, Subpart KKKK, which limits the allowable emissions from the turbines. The control technologies selected to meet the BACT derived emissions limitations; the KKKK NSPS related limitations; and the hours of operation limitations will limit the allowable emissions from the turbines.

A black-start emergency generator and fire pump engine will be installed, both diesel-powered. Both of these engines are limited to 500 hours of operation per rolling 12-month period. Compliance with applicable NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAPs) and the limited hours of operation will limit the allowable emissions from these units.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods required under applicable requirements are contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance do not require the permit to impose the same level of rigor for all emissions units. Furthermore, they do not require extensive testing or monitoring to assure compliance with the applicable requirements for emissions units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emissions unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least five years following the date of the generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emissions unit and Section V of the operating permit "General Conditions" explains the reporting requirements. However, the permittee is required to submit semi-annual and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

F. Public Notice

In accordance with ARM 17.8.1232, a public notice was published in the *Great Falls Tribune* on October 14, 2011. The Department provided a 30-day public comment period on the draft operating permit from October 14, 2011, to November 14, 2011. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process. The comments and issues received by November 14, 2011, will be summarized, along with the Department's responses, in the following table. All comments received during the public comment period will be promptly forwarded to SME so they may have an opportunity to respond to these comments as well.

Summary of Public Comments

Person/Group Commenting	Comment	Department Response

G. Draft Permit Comments

Summary of Permittee Comments

Permit Reference	Permittee Comment	Department Response
Pages i and Section I (page 1),	"Transmissions" should be revised to "Transmission."	The Department has incorporated these changes
Pages i and Section I (page 1)	"Section 24 and 25" should be revised to "Sections 24 and 25."	The Department has incorporated these changes
Page 2, for EU003 and EU004	Pollution Control Device/Practice should stipulate 500 hours per rolling 12-month period, versus 500 hours per year	The Department has incorporated these changes to ensure the table appropriately reflects the permit condition language
Section III, Condition A.2	Section III, Condition A.2 appears to be irrelevant. To promote clarity, we suggest that duplicate and/or irrelevant conditions, such as this one, be removed.	The Department has removed condition III.A.2, related to ARM 17.8.301(1) regarding the 40% opacity rule, condition III.A.12 related to ARM 17.8.324 regarding requirements applicable to petroleum tanks greater than 65,000 capacity, and condition III.A.13 related to ARM 17.8.324 regarding requirements for oil/water separators containing 200 gallons or more. These conditions are not applicable. The table and corresponding conditions have been updated and renumbered to reflect the change.
No specific condition mentioned	As a general comment, there are multiple occurrences of duplicative conditions throughout the permit. To promote clarity and facilitate compliance, we suggest that each enforceable condition be stated only once.	Title V requires that each condition relevant to a specific emitting unit be listed under that emitting unit. Therefore, there may be duplication of conditions as a facility wide condition, for example, may also be applicable to a specific emitting unit. As well, the same condition may be applicable to multiple different emitting units.
For Section III, Condition B.11	We would like to clarify when/if any action by HGS representatives is necessary, in order to monitor compliance with the opacity limit in Section III.A.1. Please clarify that opacity monitoring is necessary only upon request by the Department.	Extensive opacity testing is not required to assure compliance with the applicable opacity limit of Section III.B.1. The Department determined that natural gas fired turbines do not have significant potential to violate opacity limitations under normal operating conditions. When compliance with an underlying

		applicable requirement is not threatened by lack of regular testing and when periodic testing is not otherwise required by the applicable requirement, no or limited testing may meet the requirements of ARM 17.8.1212(1). Because a properly operated and maintained turbine burning pipeline quality natural gas would not be expected to have emissions which exceed the opacity limitations of Section III.B.1, the Department believes that SME can continuously demonstrate compliance with the opacity limit without regular Method 9 or visual survey testing. It is the Department's intent for SME to not be required to regularly perform Method 9 testing. Should the Department develop reason to believe that SME is not meeting the opacity limit of Section III.B.1, the Department reserves the authority to perform or require Method 9 testing. As noted in Section III.A.1, compliance with opacity is monitored during regular inspection by the Department's compliance inspector.
Section III, Condition C. 12 and Section III, Condition D.16	These conditions state that for "simple cycle operation, SME shall conduct Method 5 and Method 202 tests…to demonstrate compliance with the steady state PM, PM10 and PM2.5 emission limits contained in Section III.C.1" We comment on two parts of this condition: a) is it not clear why Method 5 is stipulated, when Method 5 only measures total particulate emissions and therefore cannot accurately characterize PM10 and PM2.5 emissions; and 2) why III.C.1 is referenced, when conditions III.C.5-7 state PM, PM10 and PM2.5 limits). To address both comments, we suggest that sub-conditions C.12.a and C.12.b be combined, to state that: "As required by the Department and Section III.A.1 for simple cycle operation, SME shall conduct tests on each turbine generator in simple cycle mode combusting natural gas to demonstrate compliance with the steady state PM, PM10, and PM2.5	The Department has incorporated the changes. Please note that the Department believes that stack temperatures under certain conditions may exceed the recommended temperature range of Method 201 testing.

	emission limits contained in Section III.C, using test methods as approved or requested in writing by the Department."	
Section III.D's leading table	In Section III.D's leading table, please define the stated emissions as "per stack," either in the label or in each row.	The emissions rates indicated in the Table preceding the conditions are specific to each turbine in combined cycle operation. As required by permit condition, each turbine shall have one stack dedicated to emissions from simple cycle operation, and a second stack dedicated to emissions from combined cycle operation. As specified in the permit language below the summarizing table, the emissions rate limits are per stack. The Department has clarified in the table that the emissions rates are for each stack.
Section III, Condition D.23	Section III, Condition D.23 should include the clause "for the previous month" after the text "[b]y the 25th day of each month…"	The Department agrees and has incorporated the changes
Section IV	Currently, Section IV Non-applicable Requirements does not include all of the non-applicable Air Quality Administrative Rules of Montana and Federal Regulations. Therefore, it is not clear why this section is included. Generally speaking, we feel that for the sake of clarity that the operating permit should state and address only those conditions that are applicable to this facility.	Title V requires a permit shield section of the Operating Permit. The Department has listed those rules that SME identified as non-applicable, for which the Department agreed a shield is appropriate, in this section.
Section V	Section V, Condition O.2 appears to contradict Section V, Condition C.7. Please clarify if a transfer of ownership amendment is granted permit shield or not.	Section V of the Title V permit provides a summarized description of rules. 40 CFR 70.7 states that the permitting authority may allow coverage by the permit shield in 40 CFR 70.6(f) for administrative permit amendments made pursuant to paragraph (d)(1)(v) of this section. The Department would determine applicability of a permit shield upon review of a specific scenario in which an applicability determination would be required.

Summary of EPA Comments

Permit Reference	EPA Comment	Department Response

SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS

The following table outlines those requirements that SME identified as non-applicable in the permit application but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason
40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Section 112(G) and 112(J)	Although the Department does not find SME a major source of HAPs at this time, the Department does not provide a shield for procedural rules that have specific requirements that may become relevant to a major source during the permit span.
40 CFR 63, Subpart YYYY	Although the Department does not find SME a major source of HAPs at this time, the Department does not provide a shield for rules which apply to the source category to which the facility belongs.
ARM 17.8 Subchapter 9	Although at the time of permit application, the area the facility is to be operated is not a non-attainment area, the Department does not provide a shield for: Procedural rules that have specific requirements that may become relevant to a major source during the permit span; and Rules that consist of either a statement of purpose, applicability statement, regulatory definitions or a statement of incorporation by reference.

SECTION V. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

As of the posting of the Draft of this permit, the Department is not aware of any MACT standards being promulgated which may affect this facility. The Department has determined applicability and non-applicability of current MACT standards as is discussed below:

40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines: This subpart applies to stationary combustion turbines located at a major source of HAP emissions which emit any single HAP at a rate of at least 10 tons per year (TPY), or a combination of HAPs of at least 25 TPY. This subpart does not apply to the facility at this time because emissions from the plant do not meet or exceed 10 TPY for a single HAP or 25 TPY for a combination of HAPs. This subpart would apply in the future should the Department determine that the source is major for hazardous air pollutant emissions.

40 CFR 63, Subpart ZZZZ – National Emissions Standards for hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines: The facility is currently subject to the area source requirements of this subpart for the black start emergency generator and the fire pump engine. The major source requirements of this subpart would apply in the future should the Department determine that the source is major for hazardous air pollutant emissions.

B. NESHAP Standards

As of the posting of the Draft of this permit, the Department is unaware of any future NESHAP Standards that may be promulgated that will affect this facility.

C. NSPS Standards

As of the posting of the Draft of this permit, the Department is not aware of any NSPS standards being promulgated which may affect this facility. The Department has determined applicability and non-applicability of current NSPS standards as is discussed below:

40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition (CI) Combustion Engines (ICE). This subpart indicates that NSPS requirements apply to owners or operators of stationary CI ICE that commence construction after July 11, 2005, or are manufactured after April 1, 2006. This subpart also applies to fire pump engines manufactured and certified by the National Fire Protection Association after July 1, 2006. This subpart could apply to the proposed emergency generator/engine and the fire pump depending upon the manufacture date.

40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines. This subpart applies to the proposed facility because SME proposes to install and operate stationary combustion turbines with a heat input greater than 10 million British thermal units (MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005.

D. Risk Management Plan

The Department is not aware of any regulated substance being or planned to be stored at this facility which exceeds the minimum threshold quantities for any regulated substance listed in 40 CFR 68.115 for any facility process. Consequently, this facility is not required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements three years after the date on which a regulated substance is first listed under 40 CFR 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.

E. CAM Applicability

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (unless the limitation or standard that is exempt under ARM 17.8.1503(2));
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emission of the applicable regulated air pollutant that is greater than major source thresholds.

The facility is to be equipped with continuous emissions monitoring systems (CEMS), as required by Montana Air Quality Permit #4429-00. Pursuant to the Administrative Rules of Montana, Title 17, Chapter 8, Subchapter 15, an emitting unit's emission limitations or standards for which an air quality operating permit specifies a continuous compliance determination method is exempt from the requirement of a Compliance Assurance Monitoring plan. Therefore, a CAM plan is not required of the turbines, as a CEMS is required by permit condition.

F. PSD and Title V Greenhouse Gas Tailoring Rule

On May 7, 2010, EPA published the "light duty vehicle rule" (Docket # EPA-HQ-OAR- 2009-0472, 75 FR 25324) controlling greenhouse gas (GHG) emissions from mobile sources, whereby GHG became a pollutant subject to regulation under the Federal and Montana Clean Air Act(s). On June 3, 2010, EPA promulgated the GHG "Tailoring Rule" (Docket # EPA-HQ-OAR-2009-0517, 75 FR 31514) which modified 40 CFR Parts 51, 52, 70, and 71 to specify which facilities are subject to GHG permitting requirements and when such facilities become subject to regulation for GHG under the PSD and Title V programs.

Under the Tailoring Rule, any PSD action (either a new major stationary source or a major modification at a major stationary source) taken for a pollutant or pollutants other than GHG that would become final on or after January 2, 2011 would be subject to PSD permitting requirements for GHG if the GHG increases associated with that action were at or above 75,000 TPY of carbon dioxide equivalent (CO_2e) and greater than 0 TPY on a mass basis. Similarly, if such action were taken, any resulting requirements would be subject to inclusion in the Title V Operating Permit. Facilities which hold Title V permits due to criteria pollutant emissions over 100 TPY would need to incorporate any GHG applicable requirements into their operating permits for any Title V action that would have a final decision occurring on or after January 2, 2011.

Starting on July 1, 2011, PSD permitting requirements would be triggered for modifications that were determined to be major under PSD based on GHG emissions alone, even if no other pollutant triggered a major modification. In addition, sources that are not considered PSD major sources based on criteria pollutant emissions would become subject to PSD review if their facility-wide potential emissions equaled or exceeded 100,000 TPY of CO_2e and 100 or 250 TPY of GHG on a mass basis depending on their listed status in ARM 17.8.801(22) and they undertook a permitting action with increases of 75,000 TPY or more of CO_2e and greater than 0 TPY of GHG on a mass basis. With respect to Title V, sources not currently holding a Title V permit that have potential facility-wide emissions equal to or exceeding 100,000 TPY of CO_2e and 100 TPY of GHG on a mass basis would be required to obtain a Title V Operating Permit.