Montana Department of
ENVIRONMENTAL QUALITY
Brian Schweitzer, Governor
P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

May 20, 2009

Mr. Tim Gregori
Southern Montana Electric Generation and Transmission Cooperative, Inc.
3521 Gabel Road, Suite 5
Billings, MT 59102

RE: Review of Application for Highwood Generating Station, Natural Gas Plant, Montana Air Quality Permit (MAQP) #4429-00 and Title V Operating Permit #OP4429-00

Dear Mr. Gregori:

The Montana Department of Environmental Quality (Department) has reviewed Southern Montana Electric Generation and Transmission Cooperative, Inc.'s (SME) permit application to construct and operate a gas combustion turbine facility for electric generation at the Highwood Generating Station, eight miles east of Great Falls, MT. Bison Engineering, Inc. (Bison) and Stanley Consultants prepared the application on behalf of SME. Bison delivered the hardcopy application on Friday, April 24, 2009, and delivered disks containing the electronic version with spreadsheets and modeling files on April 27, 2009.

The Department has assigned the application MAQP #4429-00 and OP#4429-00. The proposed gas combustion turbine facility and the coal-fired circulating fluidized bed (CFB) boiler facility previously permitted under MAQP #3423-00 and #3423-01 are considered to be the same source of emissions with respect to the Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs. Therefore, MAQP application #4429-00 is considered a major modification under PSD to the CFB facility. The two facilities were assigned different permit numbers for administrative reasons to simplify public and agency review of MAQP application #4429-00.

Regarding the application for construction of the gas turbine plant, the Department has deemed the application incomplete. The incompleteness issues identified in the main body of this letter address insufficient analyses and/or lack of transparency in methods and calculations provided in the permit application. These issues are fundamental to the Department's ability to issue a permit that not only provides SME with maximum flexibility in operations, but that also ensures compliance with state and federal air quality regulations.

The issues identified in **Attachment 1** to this letter address other inconsistencies, errors, and sources of uncertainty. While some of the individual issues in the attachment may seem minor, collectively the issues complicated the Department's technical review of application #4429-00. Once submitted, the requested information will bolster the underlying analysis necessary to appropriately establish permit conditions and will contribute to a more transparent process that is accessible to the broader range of stakeholders. Finally, clarification of these issues is necessary to provide an accurate account for the public record.

The Department comments are as follows:

EMISSIONS INVENTORIES. The emissions inventory provides the foundation for the regulatory framework. Such critical determinations as control technology selection are dependent on an accurate accounting of emissions. Therefore, SME must ensure calculations are accurate and highly transparent.

1. The Department must be able to replicate the process by which SME calculates emissions. To support this transparency effort, the application must show formulas and assumptions that illustrate the fundamental concepts behind the inventory calculations, and should include these formulas in the narrative where the inventories are reported. Section 3 (Emission Inventory) does not contain any formulas, and while the electronic files of Appendix C include equations embedded in the cells, these equations reference other cell locations and thus do little to illustrate the computational methods. The request to show formulas was included in the Department's *Comments on SME Salem Turbine Project Modeling Protocol*, issued to SME on March 31, 2009.
2. SME must direct the reader to the location(s) in the appendices and/or electronic files where the Section 3 tables are derived. Furthermore, SME must provide explanatory narrative to accompany tables in Appendix C, which contains over 160 tables to support emissions inventory calculations. These tables are provided electronically in six files with over twenty cross-referencing worksheets. While page 10 of the application states "Appendix C presents detailed emissions calculations and identifies sources of emission factors and other input data," there is little else to guide a reader through the analytical steps. SME must provide a short narrative at each table, or at minimum at the beginning of each worksheet, to explain what each table is calculating and why.
3. Pg. 11, Table 3-1. The Department understands the annual potential Phase I turbine emissions are calculated assuming 3,200 hours of operation at the highest possible emission rate (including startup/shutdown). The Department agrees that this is a conservative approach because the highest emissions used tend to be the startup/shutdown rates, and it is unrealistic to assume the turbines will be in constantly cycling through startup and shutdown for 3,200 hours. However, SME must clarify the methods for calculating Phase II turbine potential emissions in terms of time spent in startup and shutdown mode, and the corresponding emission factor used. Note that Pg. 37, 2nd paragraph, states, "…two startups and two shutdowns are accounted for in the emissions inventory for each day of the year." Thus, for the approximately 133 days of simple cycle operation, there would be 2 hours of startup per pay, and 2 hours of shutdown per day. For the approximately 232 days of combined cycle operation, there would be 4 hours of startup per day, and 2 hours of shutdown per day. These periods of startup/shutdown should be accounted for in the annual emissions inventory. Note the combined cycle startup is 2 hours on pages 54 and 67, 60 min in Appendix C, and 90 minutes per footnote "c" of table "COMBINED CYCLE STARTUP EMISSIONS CALCULATIONS" in Appendix C. SME must confirm appropriate value for use in annual inventory calculations. Annual inventories should be consistent throughout application: page 17 (Table 3-4), page 30 (VOC in Table 4-5), page 34 (Table 5-1), page 100 (Table 6-5), and Appendix C ("Max Case Turbine Operations").

HIGHWOOD GENERATING STATION. The Department understands that uncertainty surrounds the future construction of any permitted project. However, because there is an existing permit for construction and operation of the HGS coal plant, SME must adequately quantify impacts of the HGS coal plant as they may affect the operation and modeling demonstrations of the gas plant. The application states the gas plant will not operate when the coal plant boiler is in operation, but fails to address specifics such as non-boiler emissions or lag time following boiler shutdown.

1. Page 2, third paragraph, states, "The gas plant will not operate at any time that the coal plant CFB boiler is in operation." SME must explicitly define *operation* in terms of the status of the CFB boiler stack emissions.
2. SME must identify and include in modeling all other emitting units at the HGS coal plant that continue to operate when the CFB boiler is not operating (see following table derived from the HGS coal plant inventory). For example, Table 6-7 on page 102 must include emissions from the HGS coal plant auxiliary units and fugitive sources.

Emission Inventory from Permit #3423-01, HGS Coal Plant

Source	PM	PM10	PM2.5	NOx	SOx	CO	VOC
CFB Boiler	138	299.1	227	805.2	437.1	1150.2	34.5
Total Coal Plant Emissions	215	366	227	944	443	1177	38
Non-Boiler Emissions (= Total Emissions - Boiler Emissions)	77	66.9	0	138.8	5.9	26.8	3.5

3. SME must include all HGS coal plant structures in the gas plant modeling analysis. For example, the CFB boiler stack appears to have been omitted.
4. If the gas plant operates immediately following CFB boiler shutdown, gas plant and coal plant emissions could potentially become additive. Therefore, SME must analyze coal plant emissions dispersion following coal plant boiler shutdown to determine the period of time during which emissions from the CFB boiler disperse and become insignificant once the boiler has ceased operation. Conversely, SME must quantify the period of time during which gas plant emissions become insignificant following gas plant shutdown.

BACT ANALYSIS. The BACT analysis must ensure that controls are consistent with similar, recent determinations, and must include enough information for the Department to make appropriate regulatory determinations on BACT with respect to feasibility and economic, energy, and environmental impacts. Calculations must be transparent and replicable to ensure cost-effectiveness is based on inventories and emission rates used in the annual inventory calculations.

1. Pg. 34, Section 5.0: SME must ensure that the BACT analysis considers the most recent and available BACT determinations from comparable facilities. In the RBLC and EPA Region 4 database search results contained in Tables 5-7 (pg. 56), 5-14 (pg. 69), 5-15 (pg. 70), 5-19 (pg. 78), 5-20 (pg. 82), the most recent permit activity is September 2005 from the RBLC, and April 2007 from the Region 4 database. The Department's cursory review of the RBLC database from January 2004 through May 2009 suggests more recent permit activity. For the RBLC query, SME must clarify the search criteria used in the application, provide the full search results, explain the criteria used to determine if facilities were comparable, and which facilities were deemed incomparable and why. For any comparable facilities with lower emissions limits, explain why the proposed turbines might be unable to achieve those limits. Provide the same analysis for the Region 4 database.
2. SME must direct the reader to the location(s) in the appendices and/or electronic files where the Section 5 tables are derived. In addition, Appendix E must provide a short narrative for each worksheet and table to summarize purpose and procedure. Ensure and clarify that the inventories used in Section 3 are consistent with the inventories used in the BACT analysis. Clarify if the BACT analysis used steady-state, startup/shutdown, or some combination of emission rates. For example,

page 9 of Appendix, sheet “CO BACT Economic Analysis”, shows that CO is 8 tpy (difference between 227 tpy uncontrolled emissions and 219 tpy removed). SME must clarify how the calculations here, and throughout Appendix E, correspond with inventory calculations elsewhere in the application.

3. Pg. 76, Sec. 5.6.4. Application omits analysis for energy impacts. Provide this analysis.

MODELING ANALYSIS. The modeling analysis was inconsistent with information provided elsewhere in the application, lacked information to allow Department verification, and in some cases used incorrect or unjustified inputs. Therefore, modeling must be completed to ensure that the ambient air quality analysis and PSD increment analysis are accurate and defensible, and to ensure development of permit conditions that offer operational flexibility to SME.

1. Pg. 115, Sec. 6.5.6: SME must provide all CALPUFF output files.
2. Pg. 116, Table 6-14: CALPUFF inputs are either different from the Department draft modeling protocol (protocol) or incorrectly documented in the application. SME must address the following as they appear in the modeling files or in Table 6-14:
   a) MBDW = 1; Building downwash method is ISC (contrary to protocol; should be PRIME).
   b) MSPLIT = 0; No puff splitting (contrary to the application = 1)
   c) Table 6-14, number of emitted species = 3; model = 4.
   d) Table 6-14, vertical wind shear = yes, model = no.
   e) Table 6-14, puff splitting = yes; model = no.
   f) Table 6-14, maximum mixing height = 3,000 m; Protocol = 2,800 m.
   g) Table 6-14, IRESPLIT = Hour 17 - 22 = 1; model = 17.
   h) BCKO3 = 12 * 40; Protocol = 30 ppb Oct. - Mat, 50 ppb June - Sept.
   i) MHILL = 2; Protocol = 0 including other pertinent variables.
   j) MH2O2 = 1; Protocol = 0.
3. Pg. 118, Table 6-17: The SO_2 worst-case emissions should be included. The combined cycle worst-case NO_x emissions should be used.
4. Pg. 118, Sec. 6.5.7:
   a) CALPOST version 6.221 is now available and can accommodate the new IMPROVE equation, which is called Method 8. The Method 6 used with CALPOST v 6.221 will provide the same results as CALPOST v 5.8. SME must provide Method 2 and Method 6.
   b) Pg. 118, Sec. 6.5.7: Application states sulfate, nitrate, and PM_{10} concentrations were modeled. The Class I modeled emissions were SO_2, SO_4, NO_x, and $PM_{2.5}$ (contrary to the Bison-submitted modeling protocol that had PM_{10}, not $PM_{2.5}$). SME must model PM_{10} and clarify the source(s) used to derive the SO_4 emissions.
5. Pg. 119, Table 6-19:
   a) SME must provide the worksheet for background coefficients, including formulas and calculations.
   b) Table 6-19 had several errors according to the input files, in particular for the Bob Marshall and Scapegoat Wilderness Areas. In both cases, the 5 out of the 6 recorded coefficients were not correctly documented.

6. Appendix B:
   a) There are numerous structures listed on the plot plan that are not in the model graphics such as #45 and #15, and new structures were added such as the area southwest of the cooling towers. Therefore, Department verification of the structures listed in Appendix B after the plot plans was impossible since the corresponding item numbers did not correspond to the model variable names. For example, the Water Treatment Building is listed as Item # 27, but noted in the model as “19”.
   b) There are four new structures within the facility boundaries with variable names containing “COAL” including a coal pile of 1 ft high and about 34.5 ft in diameter. No PM emissions were accounted for from these sources in the modeling files.
   c) The locations of the emission sources must be provided in the requested UTM, NAD27 coordinates, not local coordinates.
   d) SME needs to identify the ammonia tanks.
   e) A NO_x water injection system is included in this list, but not addressed as a control technology in the BACT analysis. Provide clarification.
7. All CalpostClassIInputs.zip (Class I increment analysis) and CalpostDepositionInputs.zip (deposition) files have the same RHFAC values: (RHFAC) -- No default ! RHFAC = 2.5, 2.3, 2.2, 2.1, 2.1, 1.9, 1.7, 1.6, 1.8, 2.1, 2.4, 2.5 ! These values do not correspond to any of the five Class I areas of interest and need to be explained.
8. Each Class I areas has it own distinctive set of relative humidities which must be used; these analyses must be redone.
9. SME must identify the source of the background ammonia concentrations.
10. In the postutil files, SME must clarify source for the variable CSPECCMP for both nitrogen and sulfur species.
11. In the postutil files, SME must clarify source for the scaling factors in Subgroup 2d.

The requested information must be submitted to the Department no later than July 20, 2009. If the requested information is not submitted on or before the date specified, the application is considered withdrawn unless the applicant requests, in writing, an extension of time for submission of the additional information.

If you have any questions or concerns, please contact me by phone at (406) 444-5311 or by e-mail at blignell@mt.gov.

Sincerely,

Brent Lignell
Environmental Engineer
Air Resources Management Bureau
(406) 444-5311

cc: Hal Robbins, Bison Engineering, Inc.

ATTACHMENT 1

1. Pg. 2, Table 1-1: The Department believes the NOx value in Table 1-1 (pg. 2) is incorrectly reported as 126.34 tpy since it appears consistently elsewhere as 123.34 tpy (e.g., Table 3-1 on page 11 and Table 4.2 on page 16 of environmental assessment). SME must confirm correct value.
2. Pg. 8, last paragraph: Application states, "The proposed cooling tower will be an induced…" SME must explain the forced draft mechanism and clarify if there are associated emitting units.
3. Pg. 12, 3rd paragraph: The Department believes the text should reference Table 3-2 instead of Table 3-4. Provide clarification.
4. Pg. 14, 3rd paragraph: The Department believes the text should reference Table 3-2 instead of Table 3-3. Provide clarification.
5. Pg. 14, footnote 15: SME must clarify if the referenced "average operations" are in simple cycle or combined cycle operation.
6. Pg. 15, 2nd paragraph: SME must provide combined cycle startup data if now available from vendor.
7. Pg. 15, 3rd paragraph: SME must clarify what powers the hydraulic spin-up and any associated emissions.
8. Pg. 21, Table 4-1: Bottom left cell indicates "Error!" instead of a report section. Provide clarification.
9. Pg. 30, Table 4-5:
   a) The PM10 column should indicate 24-hour, not 8-hour.
   b) The modeled values are incorrect and should be: 24-hour PM10 = 6.6 ug/m3, 24-hour SO2 = 8.07 ug/m3, annual NOx = 3.6 ug/m3, 8-hour CO = 110 ug/m3. However, this does not affect the conclusion that pre-construction monitoring is not required.
   c) The VOC inventory of 20.06 tpy conflicts with 20.35 tpy in Table 1-1, Table 3-1, and the value of 27 tpy in Table 6-9.

12. Pg. 31, 1st paragraph: The Department assumes there will be two ammonia tanks, each with a 10,000 gallon capacity. Provide clarification, and confirm that these structures were included in modeling.
13. Pg. 39, Sec. 5.4.1.2: SME must clarify if water injection is inherent to turbine design and state the control efficiency for water injection. Item #34 in the modeling list in Appendix B includes a water injection system, but water injection is not specified as BACT. Water injection is also listed in Appendix C.
14. Pg. 44, 1st paragraph: Application states NOx control ranges from 7%-99%, but Table 5-2 only shows controls as high as 95%. Provide clarification.
15. Pg. 44-52, Sec. 5.4.4 through 5.4.5: The application lacks a clear discussion/analysis of water injection for simple cycle NOx control. If water injection is inherent to the turbine design, SME must confirm and/or indicate if this is stated in the application. Presumably water injection is an option that should be carried through the discussion of feasibility, environmental impacts, economic impacts, and energy impacts, especially since Table 5-2 shows that water injection (7-84% control efficiency) has the potential to be more effective than DLE (51-71% control efficiency). Application states that Table 5-4 demonstrated how additional controls for simple cycle were cost prohibitive. SME must clarify if water injection is inherent to the turbine design and used in simple cycle operation, and is thus included in the T1 configuration.

16. Pg. 45-46, Sec. 5.4.4.2:
    a) The Department assumes Table 5-3 represents combined cycle operation only, and that "Heat Rate" refers to the heat input as fuel energy. Provide confirmation.
    b) SME must clarify how the parameters in Table 5-3 calculate to the fuel cost difference between the 15 ppm turbine design and the 26 ppm turbine design.
    c) SME must quantify the difference between the 15 ppm and 25 ppm turbine designs in terms of cost per ton of NOx removed. SME must provide this quantitative analysis for both simple cycle and combined cycle operation, or indicate if the analysis is present in the application.
    d) The application states, "When the resulting fuel costs of the 15 ppm option are added to the cost-effectiveness of the SCR control, it becomes apparent that the 15 ppm turbine option plus the SCR control is not cost-effective." SME must clarify the specific value that is referred to by "cost-effectiveness of the SCR control". This statement requires clarification because fuel cost units are dollars-per-year ($/yr) in Table 5-3, while cost-effectiveness units are dollars-per-ton-removed ($/ton) in the economic analyses.
17. Pg. 53-56, Sec. 5.4.5.2: Application states the combined cycle startup/shutdown NOx emission rates are effective "any hour" the generating unit is in a startup/shutdown condition. SME must explain "any hour". For example, it could be interpreted that a startup that begins at 2:45 PM would mean that the startup rate applies from 2:00-3:00 PM.
18. Pg. 62-64, Tables 5-10 through 5-13: SME must explain any variation in values in the "Uncontrolled Emissions" column. Footnote "a" states that RTO includes additional emissions from reheating exhaust gas, to presumably explain why uncontrolled emissions increase from 78 tpy to 86 tpy. However, since these are uncontrolled emissions, the control devices would not operate and should not therefore add to emissions.
19. Pg. 62, Table 5-10: In the Catalytic Oxidizer section of the table, SME must explain variation in control efficiency; i.e., 86-96% with no indication of the 95% control presented in Table 5-8.
20. Pg. 63, Table 5-12: SME must explain why control efficiency in the RTO section ranges from 82-96% with no indication of the 95% control from Table 5-8.
21. Pg. 67 and 68: SME must explain implications of "any hour" for CO and VOC startup/shutdown rates (see similar comment for NOx rates, pgs. 53-56).
22. Pg. 68, 2nd paragraph: In the section "Simple Cycle Startup and Shutdown", SME must clarify why there is a discussion of the DLE system as CO and VOC control. Simple cycle BACT for CO and VOC was presented as proper system design and operation (pg. 64).
23. Pg. 85, Sec. 5.8.1.4: Application states that an economic evaluation of controls is not provided for generator and fire pump controls because the emission reductions due to intermittent and infrequent use is difficult to quantify. However, it would seem that an analysis could reasonably be based on 500 hours of continuous operation, or on the planned engine test/maintenance schedule.
24. Pg. 90, Table 5-29: Note that the PM/PM10/PM2.5 and SO2 values for steady-state operation are also the values for startup/shutdown (which are not otherwise indicated in the table).
25. Pg. 92, 3rd paragraph: The application should reference Table 1 in the MMGAQP instead of Table 7.
26. Pg. 93, Table 6-1: The SO2 3-hr average should be 25 ug/m3, and the SO2 annual average should be 1 ug/m3.
27. Pg. 94, Table 6-2: Like Table 6-15 on page 117, this table is inconsistent with Table 4.1 on page 14 of the Appendix G environmental assessment in terms of the number of Class I areas and the distance to those areas.
28. Pg. 98, Sec. 6.1.5: The Department finds 13,627 total receptors in the SIA analysis, which include 1,493 from the PM2.5 NAAQS, 327 for NOx, 327 for PM10 , not the 1,312 reported in this section.

29. Pg. 100, Table 6-5:

    a) SME must verify all values in table – it appears that the lb/hr values for simple cycle startup are actually the combined cycle steady state, and vice versa, which would also impact the results in the tpy columns.

    b) The table reports cooling tower PM at 1.029 tpy and 0.235 lb/hr, which conflicts with the first page of Appendix C where PM is listed at 1.14 tpy and 0.26 lb/hr. Provide clarification.

30. Pg. 101, Table 6-6: The parameters below differ from those in the modeling files or are inconsistent in the application. Provide clarification of the following:

    a) The simple cycle west stack steady-state UTM coordinates differ from the simple cycle west stack startup/shutdown coordinates, when presumably this should be the same stack. The same is true for simple cycle east, and combined cycle east and west.

    b) It appears that the combined cycle steady state stack height should be 105 ft instead of 80 ft, and the simple cycle startup/shutdown stack height should be 80 ft instead of 105 ft.

    c) The combined cycle steady state stack velocity of 105 ft/sec is reported as 66 ft/sec on page 14 of the application form in Appendix A, and as 66.4 ft/sec in the modeling files. Confirm correct value.

    d) The Fire Pump gas exit velocity and inside stack diameter were modeled as reported on page 30 of Appendix A at 27.9 ft/s and 1.25 ft, respectively, not as listed in Table 6-6 as 170 ft/s and 0.5 ft, respectively. Confirm correct value.

    e) The Black Start Generator gas exit velocity and inside stack diameter were modeled as reported on page 26 of Appendix A at 37.6 ft/s and 2.5 ft, respectively; not as listed in Table 6-6 as 170 ft/s and 0.67 ft, respectively. Confirm correct value.

    f) The Fuel Gas Compressor Building gas exit velocity was modeled as 84.9 ft/s, not the listed 170 ft/s; the application does not list the corresponding parameters for each building to verify.

31. Pg. 104, Table 6-9: The VOC simple cycle startup/shutdown rate should be 3.90 lb/hr, not 3.09 lb/hr, which would change turbine emissions from 148 lb/day to 187 lb/day, and 27 tpy to 34 tpy. However, the Department recognizes that this is not significant because the annual VOC emissions are well below the modeling thresholds of 548 lb/day and 100 tpy.

32. Pg. 105, Table 6-10:

    a) The highest 1-hour CO concentration occurred in 2003 not 1999. The emission source group remains unchanged.

    b) The highest 8-hour CO concentration occurred in 2002 not 1999 from the CC_SS emission group.

    c) The met data for the highest 24-hour PM2.5 concentration should be the same as the 24-hour PM10 met data since PM2.5 equals to PM10. Therefore, the met year should be 2002, not 1999.

    d) The table should include results for SO2 annual, 24-hr, 3-hr, and 1-hr analyses.

33. Pg. 105, Table 6-11: The MAAQS/NAAQS results should be corrected as follows, although the corrections will not affect the overall results: The highest annual PM2.5 is from the CC_SS emission group, not CCSTEADY, with 0.929 ug/m3 and including background of 5.88 ug/m3 would be 6.81 ug/m3, not the listed 6.74 ug/m3.

34. Pg. 111: The current CTGPROC version is 2.682, Level 07430, not Version 2.681, Level 070327.

35. Pg. 113-114: Application lists 40 surface met stations but the narrative states 39 stations are in the surface data. Provide clarification.

36. Pg. 115: MESOPUFF III should be MESOPUFF II.

37. Pg. 117, Table 6-15: Like Table 6-2 on page 94, this table is inconsistent with Table 4.1 on page 14 of the Appendix G environmental assessment in terms of the number of Class I areas and the distance to those areas.

38. Pg. 117-118, Tables 6-16 and 6-17: Regarding the CALPUFF analysis:

    a) Tables and associated modeling should include emission from the entire gas plant facility, not just the turbines.

    b) Table 6-16: The Combined Cycle stack heights is listed as 27.43 m, but modeled as 32.004 m. Same for Class II modeling.

    c) Table 6-16: The Simple Cycle stack height is listed as 18.29 m, but modeled as 24.38 m. Same for Class II modeling.

    d) The combined cycle NOx rate in Table 6-17 should be the worst case rate of 26.12 lb/hr, not 4.16 lb/hr.

    e) Table 6-17 should include SO2.

    f) Table 6-17 should note that PM is representative of PM10 and PM2.5.

39. Pg. 119, Section 6.5.8: This paragraph should clarify that impacts from SO2, NOx, PM2.5, and PM10 emissions are summarized, not just emission from SO2.

40. Pg. 120-123, Tables 6-20 through 6-23: These tables should reflect the highest NOx rate of 26.12 for combined cycle operation as done in the Class II analysis.

41. Appendix A, pg. 7: The PM and SO2 annual rates appear to reflect operation of two turbines, not "each" as indicated in the table. Methods for calculating annual rates for NOx, CO, and VOC should be discussed with the Department.

42. Appendix A, pgs. 26 and 30: There is a significant difference between the emergency generator exhaust gas temperature (763.5 F) and the fire pump engine exhaust temperature (1032 F). Confirm values and/or provide vendor data.

43. Appendix C, sheet "MISC EQUIPMENT EMISSIONS" (electronic file "C2 PTE Emissions Summary – V8.xls", worksheet "Bldg_Htrs_EDG_Firepump"): Regarding the "Caterpillar" reference, SME must provide data for engines and more information about the reference (e.g., was it correspondence? a data sheet?). Do the horsepower ratings for the emergency generator (2514.375 hp) and fire pump (308.43 hp) reflect the power output at the engine or the power output at the generator/pump? Engine output should be used for emissions inventory calculations. Also, the hourly emission rates in AP42 for the emergency generator and fire pump are higher than those referenced by Caterpillar. SME must provide the Caterpillar data to justify Caterpillar rates.

44. Appendix E: File E11 should be TI, T2, S1, not S2 as appears in spreadsheet (filename is correct).

45. Appendix F: The 1999 - 2001 PM10 24-hour SIA graphics were missing from the submitted CD and Appendix F. Provide graphics.

46. Appendix G, pg. 14, Table 4.1: SME must ensure table is consistent with Tables 6-2 and 6-15. The Class I analysis did not include Mission Mountain and Anaconda Pintler Wilderness Areas.

47. Appendix G, pg. 16, Table 4.2: Total annual simple cycle NOx is inconsistent with Table 1-1.

48. Appendix G, pg. 17: Calculations for CO2 are based on 4,380 hours of operation, which the Department assumes is based on the estimates for actual operation. To be consistent with annual inventories elsewhere in the application, the potential-to-emit should be included based on 8,760 hours of operation (3,200 hours in simple cycle operation, and 5,560 hours in combined cycle operation).

49. Appendix G, pg. 19, Table 4.5:
    a) Table 4.5 NO2 values should match Table 6-11.
    b) PM10 annual NAAQS do not exist.
    c) PM2.5 MAAQS do not exist for either 24-hour or annual.
    d) The NOx concentrations in this table are different than Table 6-11, which have been verified.
    e) Despite footnote "a", selected concentrations were not consistently from the steady-state modes.
    f) There is a footnote "c" in this table without reference.
50. Appendix G, pg. 20, Table 4.6:
    a) Table 4-5 NOx should match Table 6-12.
    b) PM10 annual concentrations were not modeled, so it is misleading for the table to report a value of 0; the cell should be "NA" or "--".
    c) Despite footnote "a", selected concentrations were not based on steady-state modes. Modeling should use the worst startup/shutdown rates as used in other modeling demonstrations in this application.
51. Appendix G, pg. 23: The second paragraph indicates ten families within a two-mile radius, conflicting with page 28 that indicates eight families within a three-mile radius.
52. Appendix G, pg. 41: According to the EA, the gas plant will not be visible from the Interpretive Viewpoint. Confirm that this includes the four turbine emissions stacks.

MODELING FILES

53. Buildings and structures appear to be rough estimates since they are not square.
54. The simple cycle SUSD east and West (HI_SCE and HI_SCW) exit gas velocity is very high, 55.1 m/s; confirm that values are correct.
55. The Fuel Gas Compressor Building exit velocity fluctuated between 25.87 and 51.74 m/s between the files; SME must specify the correct value.
56. On the plot plan, one emission point (#18) is not a tank. This is for ammonia storage. No tanks were identified for ammonia storage in the modeling file.
57. It does not appear that the postutil program was used to repartition the nitric acid and nitrate concentrations in the visibility analysis contrary to the Department draft BART protocol. Provide clarification.
58. In the calpost input files, SME must explain the following entry for the threshold for 24-hr averages: (THRESH24) ! THRESH24 = 0.2.
59. SME must explain why a 95% maximum relative humidity was selected in the CALPOST files.
60. SME must explain why water treatment and waste water stacks are shorter than the buildings (the heights are measured from the ground level).
61. The modeling used startup/shutdown lb/hr emissions, but steady-state stack temperature and velocity. SME must clarify any differences between startup/shutdown temperatures/velocities as compared to steady state temperatures/velocities. SME must verify (through modeling or adequate narrative) that using the startup/shutdown operating conditions (i.e., stack temperatures and velocities) would not cause another pollutant to be modeled (i.e., result in definition of a significant impact area) and a violation of a NAAQS/MAAQS would not occur.

AERMET

62. Location of Great Falls is more accurately located at 47.473145N, -111.38301W NAD83 compared to coordinates used (47.473330N, -111.382220W) according to the link http://itouchmap.com/latlong.html. The distance between these two points is approximately 63 meters (207 feet).
63. The Great Falls upper air site is 47.46N, -111.38W, not 47.45N -111.38W. The distance between these two points is 1.1 km.

OFF-SITE EMISSIONS

64. As stated on page 102, Sec. 6.1.7.2, the electronic Appendix F files do not contain spreadsheets with further descriptions of surrounding sources. SME must provide the electronic files for these spreadsheets, including formulas and calculations, for the surrounding sources. Inventories of these sources should be included as tables in the Appendix.
65. Malmstrom AFB MAQP #1427-08 lists the total NOx emissions as 249.8 tpy yet the NOx modeling files list 232.4 tpy for each of 2 boilers (232.4 * 2).
66. MRC included 1.05 tpy NOx emissions for KEROSENE when the Department worksheet had none. There were also PM emissions for this source when the Department had none. SME must explain these determinations.
67. MRC included PM emissions for the TK56 when the Department worksheet had none. SME must explain this determination.
68. SME must explain difference between Montgomery combined cycle turbines NOx long-term (39.1 tpy - correct) and short-term (40.65 tpy) emissions.
69. SME must explain difference between Montgomery fire pump NOx long-term (0.98 tpy - correct) and short-term (0.02 tpy) emissions.
70. The PM10 + PM2.5 emissions from Montana Waste Systems, Inc. should be 24.4 tpy, not 20.5 tpy as used in the modeling.
71. SME must explain why all of the Malteurop PM emissions are different from those provided by the Department by an overall increase of 3.3 tpy and do not reflect MAQP #3238-05.
72. SME must explain why following MT Ethanol PM sources are different than the emissions in MAQP #2835-06:

Source	#2835-06 (tpy)	SME Application (tpy)
30_DDGSB	25.0	0.3
33_ST	0.27	11.8
34_BOIL	11.8	0.1
37_GLTBL	0.07	0.06
32_DDGSL	0.30	0.24
35_COOL	15.00	4.49
42_GBD	0.10	0.03
43GBBFVF	0.10	0.03