12/1/09

Response to Forest Service
Comments October 14, 2009

General Comments

Comment 1: We agree with previous comments by the National Park Service (NPS) that Theodore Roosevelt National Park should be treated as one Class I area, not three.

Response: North Dakota has two Class I areas within its boundaries: the Theodore Roosevelt National Park which consists of three separate and distinct units and the Lostwood National Wildlife Refuge Wilderness Area. The North Dakota Department of Health (Department) considers the three units of Theodore Roosevelt National Park to be three separate areas for modeling purposes for the following reasons:

A. Theodore Roosevelt National Park (TRNP) as a PSD Class I area consists of three units (see 44 FR (November 30, 1979) at 69125 and 69127, 40 CFR § 81.423 and NDAC § 33-15-15-01.2 (Scope) relating to 40 CFR 52.21(e)). The areas are not contiguous. The North Unit and South Unit are separated by approximately 38 miles.

B. Federal regulation, 40 CFR 51.301, states "*Adverse impact on visibility* **means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent,** intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Federal Class I areas, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas." (Emphasis added) Combining the three units of TRNP into a single area for visibility analysis fails to address the "geographic extent" of any visibility impairment.

C. The North Unit is not visible from the South Unit and vice versa. The commingling of receptors from the units for a visibility analysis misrepresents the ability of a park visitor to observe features in another unit.

   Any viewable scenes outside any unit of TRNP from within the unit are "integral vistas". The effects on integral vistas are not considered when determining whether an adverse impact on visibility will occur. There are no geological features, terrain or structures in any unit of TRNP that are viewable from another unit across the land regions separating the units. For example, terrain peaks in the South Unit would have to rise at least 900 feet above terrain in the North Unit, due to the Earth's curvature, to be seen by a visitor in the North Unit. So the visual range of visitors in one unit does not include aspects of another unit.

D. The Department has treated the units as separate Class I areas for 30+ years for purposes of PSD increment consumption without objection from EPA or the FLMs prior to 2006.

E. Treating the three units as a single Class I area effectively extends Class I status to areas between the units which are classified as Class II by rule and law.

F. The units have three different names, the South Unit, the North Unit and the Elkhorn Range Unit.

Comment 2: In a number of places in the RH SIP, ND characterizes its impact on its own class CIAs as "small." We note that this is a subjective term. Based on our review of RH SIPs from other states, we do not consider ND's percent contribution to visibility impairment in its own CIAs as being significantly different (i.e. smaller) than the other CIA owner states. For example ND's contribution to its CIAs is very similar to Minnesota's contribution to its CIAs. If ND feels this is not true, ND should include data to support this position. Nevertheless each State must demonstrate that it is obtaining "*its share of the emission reductions needed to meet the progress goal for the area,*" per 40 CFR 51.308 (d) 3.

Response: We agree that "small" is a subjective term. However, Canada and sources outside the WRAP's modeling domain are larger contributors to visibility impairment in North Dakota's Class I areas. North Dakota sources contribute 21% or less of the visibility degradation to TRNP and LWA. We believe the word "small" is an appropriate descriptor.

Comment 3: The RH SIP should explain how the reasonable progress goals (RPGs) will be revised once the RH SIPs from the neighboring contributing states are available.

Response: The following paragraph has been added to Section 11.3.
In addition, North Dakota commits to revise the implementation plan, including the reasonable progress goals, once RH SIPs from neighboring states become available and are approved by EPA, or if the unexpected or unforeseen occurs. This would include, but not limited to, projected future emissions reductions that do not occur, are distributed differently over an alternate geographic area, or are found to be incorrect or flawed. These revisions will be made within one year as required by §51.308(d)(4). North Dakota also commits to accelerate this revision schedule if the present RH SIP is found to be significantly flawed and the 2018 reasonable progress goals cannot be reasonably attained.

Comment 4: We note that the State of Minnesota specifically asked ND to analyze the feasibility of reducing electrical generating unit (EGU) emissions in the state to less than 0.25 pounds per million Btu (lb/MMBtu) for sulfur dioxide (SO_2) and less than 0.22 lb/MMBtu for nitrogen oxides (NOx). We found a response from ND that outlined their disagreement with the premise of Minnesota's "ask." Additional information would be helpful comparing the emission level of ND's EGUs after the installation of controls prescribed under the Best Available Retrofit Technology (BART) and Reasonable Progress (RP) analyses.

Response: We believe the lb/10^6 Btu metric proposed by Minnesota is inappropriate since it is not based on the four factors that must be considered as required by rule and law. We believe cost must be considered, especially on a dollar per deciview basis.

Comment 5: We ask US EPA Regions 5 and 8 to arbitrate the disagreement between ND and Minnesota regarding Minnesota's "ask," as well as working with Canada on reducing emissions from sources in that country, especially the power plants mentioned by ND on page 53 of the RH SIP. This is especially relevant since power is sent across the US-Canada border.

Response: None required

General BART

Comment 6: We feel the decision to make Heskett Unit 2 not subject to BART is based on inappropriate modeling. Technical reasons were discussed on the call between ND and the Federal Land Managers (FLMs) on September 22, 2009, including the use of using fine grid (1 km) modeling. Department of Interior modeling staff will provide more details. Please complete a full BART analysis for this unit. Alternatively, if Heskett is not found to be subject to BART it should be included in the State's reasonable progress analysis and a complete suite of possible control options examined in detail.

Response: Heskett Unit 2 is being reevaluated. This source will be addressed in a future supplement to this SIP revision.

Comment 7: We would also like to note that the statement that Heskett is proposing a 70% SO_2 emission reduction is misleading. Baseline SO_2 emissions were reported as 2400 tons and the reduction project was reported to reduce emissions by 740 tons. This results in a 31% reduction.

Response: So noted

Comment 8: EPA BART guidelines (Federal Register, July 6, 2005) on page 39170 directs the State to compare the 98 percentile days, pre-control versus post-control, so we disregarded the 90 percentile days presented in the RH SIP on page 67.

Response: The affected sources and the Department have provided both the 90th and 98th percentile results for the reader. The only facility in North Dakota that is subject to the BART guideline is Coal Creek Station for NO_x only. The BART Guideline states "For sources other than 750 MW power plants, states retain the discretion to adopt approaches that differ from the guideline." Therefore, the Department is allowed to consider any type of visibility improvement information in determining BART.

Comment 9: On page 68 ND states "Though single-source modeling is specified in the BART guidance for determining degree of visibility improvement, it is clear that this modeling overstates the real single-source visibility impact." Please add a reference or basis for this statement. ND also adds "an observer's perception of visibility change is affected by the total loading of visibility-affecting species in the atmosphere." We agree. On clean days visibility can be impaired by a small amount of air pollution. That is why it is important to use clean days as a baseline from which to measure impairment from a source. Otherwise clean days are not protected.

Response: Visibility on clean days is being protected, as demonstrated by WRAP and NDDH results for the 20% cleanest days. The modeling results for the 20% cleanest days indicate no deterioration of visibility on the 20% cleanest days at North Dakota Class I areas. But according to the Regional Haze Rule, the focus of visibility improvement demonstrations is the *20% worst visibility days*, not the cleanest days. There is no requirement to make the cleanest days cleaner, the Rule specifies only that visibility on cleanest days should not degrade. A calculated visibility change using single-source modeling is only accurate or applicable during clean visibility background conditions, when a Class I area is impacted by a single source's plume. This is certainly not the case for the 20% worst visibility days. For the 20% worst visibility days, a realistic change in visibility must be calculated with respect to current baseline conditions, which include the cumulative impact of many sources. Given that the deciview calculation is based on the observer's perception, single source modeling will overstate perceived visibility change on the 20% worst days.

The basis for the NDDH statement on single-source modeling overstating the real impact relates also to the cumulative visibility improvement analyses conducted by WRAP and NDDoH for 2018. These sophisticated analyses indicate that overall visibility improvement (20% worst days) will actually be much lower than the additive impact of single-source modeling associated with BART degree of visibility improvement. In other words, the single-source modeling results conflict with the results obtained by WRAP. You cannot claim the single-source modeling is accurate for depicting real visibility improvement without disparaging the results obtained by WRAP. The NDDoH believes the sophisticated WRAP modeling is more accurate.

Comment 10: In the BART section of the SIP ND appears to disregard the importance of EPA's presumptive BART limits. EPA considers these limits to be "generally cost effective" and in the case of scrubbers states, "We expect that scrubber technology will continue to improve and control costs continue to decline" (FR, 7/6/07, pg 39171).

Response: The Department did not disregard the presumptive BART emission rates. As pointed out earlier, only Coal Creek Station (for NO_x only) is subject to the BART guideline and presumptive BART emission rates. Coal Creek Station will meet the presumptive limits for NO_x. Although not subject to the presumptive levels, Leland Olds 1 will be below the NO_x presumptive level. All sources except Stanton 1 will be required to meet the presumptive level for SO_2 even though the presumptive levels do not apply.

SO_2 BART

Comment 11: MR Young Unit 2

A. We feel the form of the emission limit needs to be reviewed. For example, the emission limit is specified as 95% control efficiency (CE). Therefore the pounds per million Btu (lb/MMBtu) limit should be 0.1 or else the effective limit becomes 0.15 lb/MMBtu which is 90% control. MR Young Unit 1 is specified as having just a CE limit and no alternative lb/MMBtu. If Unit 1 can comply with just a CE limit we see no reason why Unit 2 can't also do the same.

B. At the end of the BART analysis, ND changes the baseline emission level from 2.0 lb/MMBtu to 3.5 lb/MMBtu, which effectively raises the final BART limit. We feel the same baseline emission level should be used throughout the whole BART analysis, which includes calculating the costs per ton, as well as setting the limits.

Response:

A. The commenter is incorrect in the assertions on the SO_2 emission rates. If average sulfur content coal is burned, 95% removal efficiency will be 0.11 lb/10^6 (annual average) and 0.17 lb/10^6 Btu based on a reasonable worst-case sulfur content of 1.46% (worst-case sample was 5.6%). To obtain a 30-day rolling average emission limit, the annual average would have to be adjusted up approximately 33%. This yields a 30-day rolling average based on 95% reduction of 0.15 lb/10^6 Btu for the average coal and 0.23 lb/10^6 Btu for a reasonable worst-case. Minnkota has agreed to limit emissions to 0.15 lb/10^6 Btu or 95% reduction. The Consent Decree for the facility requires a minimum of 90% reduction. Therefore, when Minnkota chooses to comply with the 0.15 lb/10^6 Btu, they will also have to achieve at least 90% reduction. Based on average coal sulfur 95% reduction will be required to comply with the 0.15 lb/10^6 Btu limit. Under the Consent Decree, Unit 1 does not have the option of meeting a 0.15 lb/10^6 limit.

B. The calculations in the Department's analysis have been revised based on the projected increase in sulfur content to 0.93% from the baseline of 0.86%. The <u>annual average</u> sulfur content was used for the analysis and the projected emission rate of 0.11 lb/10^6 Btu (annual average) was then adjusted to a 30-day rolling average of 0.15 lb/10^6 Btu. The higher "reasonable worst-case" sulfur content was not used to determine the emission limit of 0.15 lb/10^6 Btu on a 30-day rolling average basis."

Comment 12:

A. It is unclear why this unit can't install a wet scrubber and meet the same limit as the Leland Olds Unit 1 (95% CE) which is a boiler of similar size, age, firing type, and is also along the Missouri river. Please include a discussion of how the relevant BART factors are different for the two units. The costs for a wet scrubber at Stanton appear to be reasonable ($1480/ton).

Response: The Department eliminated a wet scrubber from consideration as BART at Stanton Unit 1 based upon a combination of factors. These include the relatively high incremental cost of $4,179 per ton of SO_2 removed when burning lignite and $6,302 per ton of SO_2 removed when burning PRB, the additional environmental impacts of a wet scrubber and the fact that a wet scrubber will remove a relatively small amount of SO_2 when compared to a spray dryer (with a small corresponding visibility improvement).

The additional environmental considerations are further outlined below:

- A wet scrubber is estimated by Great River Energy (GRE) to use as much as 20% more water or approximately 15 million gallons per year of additional water.

- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.

- Dry scrubbers are purported to achieve higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Although Leland Olds Unit 1 and Stanton Unit 1 are both located on the Missouri river, the facilities are not located at the exact same location. As indicated above, site-specific factors were considered when making the determination to eliminate a wet scrubber from consideration as BART at Stanton Unit 1. Basin Electric, operator of Leland Olds 1, also has a much larger area available for siting a dewatering pond.

B. Again, for this source, ND adjusted the baseline emission rate up for both fuels (i.e. from 1.8 to 2.4 lb/MM Btu for lignite and from 1.2 to 1.6 lb/MM Btu for sub-bituminous). As stated above we feel the baseline emission rate should be the same throughout the analysis. If the baseline emission rate were the same throughout the analysis, it would reduce the cost per ton presented, which already appears to be reasonable.

Response: The Department's economic analyses were based on uncontrolled <u>annual</u> SO_2 emissions of 1.81 lb/million Btu for lignite and 1.2 lb/million Btu for PRB coal. The proposed BART emission limits for SO_2 are based on a <u>30-day rolling average</u> (as opposed to an <u>annual average</u>) with 90% reduction and also includes emissions from startups, shutdowns and malfunctions. Based upon historical SO_2 emissions data for spray dryers and fabric filters at facilities burning North Dakota lignite, we have determined that an increase of 33% is warranted to adjust from an <u>annual average</u> SO_2 emission rate to a <u>30-day rolling average</u> emission rate. The discussion regarding potential SO_2 emissions as high as 2.4 lb/million Btu for lignite and 1.6 lb/million Btu for PRB coal was intended to show that higher sulfur coal could be encountered (see Appendix E, Sulfur Content Statistical Analysis, of the GRE BART Analysis). The Forest Service states that the cost per ton for SO_2 removal already appears to be reasonable. The Department agrees that the wet scrubber cost effectiveness of $1,480/ton of SO_2 removed when burning lignite and $2,232/ton of SO_2 removed when burning PRB are reasonable. However, the Forest Service chooses to ignore the relatively high incremental cost of $4,179 per ton of SO_2 removed when burning lignite and $6,302 per ton of SO_2 removed when burning PRB. As indicated in the response to comment #12.a. above, the Department appropriately considered the five factors when making the decision to remove a wet scrubber from consideration as BART at Stanton Unit 1.

NO_x BART

Comment 13: We would like to comment on an ancillary issue. ND states in the individual BART determinations, "The Department believes pilot scale testing would prove to be very beneficial in addressing the items of concern and provide a more detailed professionally reliable cost estimate. However, the BART process cannot mandate pilot testing be conducted to determine costs." We agree and suggest that should a decision be made not to apply SCR with this SIP, additional pilot testing would be useful and encourage ND to include enforceable schedules in the long term strategy portion of its RH SIP. Minnesota took just such an approach in its RH SIP for the taconite industry which, like lignite fired power plants in North Dakota, had little data on NOx controls and is almost entirely in one state.

Response: Although we believe it would be beneficial to have pilot test data, the Department must make its decision regarding BART based on available data. The U.S. EPA, Region 8 has indicated that such "commitments" within the regional haze SIP are unacceptable and would not be considered in determining whether to approve the SIP.

The Department has been working with industry to get pilot testing completed. By the next planning period, we expect to have much more data.

Comment 14: We note that Leland Olds Unit 2 and MR Young Units 1 and 2 do not meet presumptive BART, which as noted above is described by EPA as "generally cost effective."

Response: These sources are not subject to the BART guidelines or the presumptive BART emission limits. EPA did not address the flue gas characteristics of North Dakota lignite when determining the presumptive levels. The BART guideline states "As with other presumptive limits established in this guideline, you may determine that an alternative level of control is appropriate based on your consideration of the relevant statutory factors." The Department has based its BART decision on the relevant factors and selected a level of control different from the presumptive level. Our explanation for our selection is found in the SIP, Appendix B.

Comment 15: The startup/shutdown BART exemptions proposed for MR Young Units 1 and 2 are not necessary since the limit will be in the format of a 30 day rolling average. We have not seen such exemptions in BART determinations in other states. Four other BART units in ND are also using SNCR and are not asking for similar treatment. If these exemptions are allowed they should be severely limited by enforceable permit conditions, otherwise the integrity of the BART limit will be compromised.

Response: The BART exemption for startup is necessary since Minnkota did not build excess emissions during startup into the proposed BART limit (see discussion in Minnkota's October 2006 analysis – Appendix C). Minnkota prepared a BART analysis which is consistent with the BACT analysis required by their Consent Decree. The Consent Decree, paragraph 66 requires Minnkota to address startup NO_x emissions separately. Therefore, the BART limit is being proposed to be consistent with the BACT limits. Other facilities have included startup/shutdowns in their proposed BART limits. Leland Olds Unit 2 has a baseline emission rate of 0.67 lb/10^6 Btu compared to Minnkota Unit 1 which has a baseline of 0.78 lb/10^6 Btu.

The proposed BART limits are identical at 0.35 lb/10^6 Btu except for a separate limit for Minnkota during startup.

Comment 16: We applaud ND for the process it took to identify sources for which additional controls could be potentially applied under reasonable progress. Based on the Q/d metric, clearly Coyote and Antelope Valley Station (AVS) have visibility impacts that are on par with, or exceed many of the subject to BART sources. These subject to BART sources were all prescribed to install additional SO_2 and NO_x controls by ND in the draft SIP.

a. SO_2 - Improvements to the existing spray dryer system should be included as an option, and costs determined, in the control technology analyses done for the AVS units. EPA states the following for existing flue gas desulfurization systems in their BART guidelines, "There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems…" This is the approach taken by ND for the Coal Creek units and MR Young Unit 2.

b. NO_x - When comparing the emission rates from AVS and Coyote to the rest of the State's EGUs, AVS and Coyote would be the newest and the dirtiest. We note that ND states that moderate control options such as LNB/SNCR at 65% CE for AVS and ASOFA/SNCR at 55% CE at Coyote are reasonable (page 180 of the RH SIP).

ND claims that the improvement in visibility from installing controls at AVS and Coyote is too small to require their installation. It is unclear which modeling method/protocol was used to produce the visibility results in Table 9.9, which makes their use problematic. Nevertheless AVS and Coyote are of the same general size, and located in the same general area, as the BART sources. Therefore we feel reductions at AVS and Coyote are equally important to those at the BART sources. ND required controls at the BART sources. The amount of reductions from AVS and Coyote are significant – in the range of 30,000 tons of combined NO_x and SO_2, not including any additional SO_2 that could be reduced from upgrading the spray dryers at AVS. Please consider controls on AVS and Coyote such as LNB/SNCR at 65% CE for AVS and ASOFA/SNCR at 55% CE at Coyote.

Response:

a. Improvements to the spray dryers at AVS I and II are underway. This has been noted in the revised SIP. The Department looked at the improvements to the scrubber system at Antelope Valley Station. This included meeting the presumptive emission rate of 0.15 lb/10^6 Btu. When this emission rate was modeled with the presumptive NO_x emission limit, it only improved visibility 0.045 deciviews at LWA and 0.031 deciviews at TRNP during the 20% worst days (total for the two units). For the Coyote Station, visibility improved only 0.04 deciviews at LWA and 0.02 deciviews at TRNP when the scrubber efficiency was 95% and NO_x emissions were reduced 55%. The Department considers this amount of improvement to be unsubstantial.

b. The Department considered the cost to be reasonable on a dollar per ton basis. However, EPA's guidance for determining reasonable progress states "Therefore, in assessing additional emissions reduction strategies for source categories or individual large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." The Department evaluated the cost on a dollar-per-deciview basis and found it to be unreasonable.

The modeling in Table 9.9 was based on a cumulative analysis of the improvement in the 20% worst days. The Department will further describe the modeling procedure in the SIP.

Comment 17: Under the section on "Energy and non-air quality environmental impacts," we encourage ND to include the environmental and health *benefits* of installing additional controls. In general, the benefits of installing controls on EGUs far outweigh the costs.

a. For example the report EC/R did for Midwest RPO (http://www.ladco.org/reports/rpo/consultation/index.php) shows that the health benefits of reducing SO_2 and NO_x emissions under a region-wide SO_2 and NO_x control strategy are generally expected to outweigh the costs of control. These health benefits stem from the reduced ambient levels of PM and ozone which would result from the control of SO_2 and NO_x. "When benefits in the entire modeling domain were considered, the estimated values of these benefits outweighed the projected costs of control by more than a factor of 10" (page 106). This does not include other environmental benefits of controls which are harder to quantify but nonetheless important (e.g. reduction in mercury deposition).

b. In the original Clean Air Interstate Rule (CAIR), the range of annual *net* benefits (benefits less costs) to society were calculated to be approximately \$71.4 to \$60.4 billion in 2010 and \$98.5 to \$83.2 billion in 2015 (FR 5/12/05, pg 25305).

Response: (a & b)

The Energy and Non-Air Quality Environmental Impacts Analysis does not address health effects from air emissions. As stated in the BART guideline "In the non-air quality related environmental impacts portion of the BART analysis, you address impacts **other than air quality** [emphasis added] due to emissions of the pollutant in question. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device."

Even though health effects are not evaluated under this section of the BART analysis, the Department reviewed ambient monitoring day in the vicinity of Antelope Valley Station and Coyote Station. Five ambient monitors are operated in the immediate area. In 2008, the maximum 3-hour SO_2 concentration was 39 ppb (7.8% of the NAAQS), the maximum 24-hour SO_2 concentration was 9 ppb (6.4% of the NAAQS) and the maximum annual average was 1.8 ppb (6% of the NAAQS). For NO_2, the maximum annual average was 2.7 ppb (5.1% of the NAAQS). Given the low concentration of these pollutants, any benefits to health would be extremely hard to quantify.

Comment 18: We do not support the method used to adjust the glidepath to account for Canadian emissions used in the RH SIP. We do support DOIs suggesting of using species-specific information provided by the Western Regional Air Partnership (WRAP).

Response: Regarding the statement, "we do not support the method used to adjust the glidepath for Canadian emissions used in the RH SIP", the commenter does not state what is wrong with the method, nor is any alternative provided. Therefore, the NDDoH has no basis to respond to this comment. As indicated in the SIP, the NDDoH approach for the adjusted glidepath is intuitive and consistent with proposals from other organizations (e.g., CENRAP Policy Oversight Group – Summary of PM Source Apportionment Modeling and 2018 Projection Approaches, March 2007).

WRAP species-specific information is included in Section 8 of the SIP.

Comment 19: We found no specific discussion in the draft SIP that considered contingency measures or procedures which could be triggered if the unexpected or unforeseen occurs. For example, if projected future emissions reductions do not materialize, or are distributed differently over an alternate geographic area, emission inventories could be found to be incorrect or flawed. Are there adaptive management strategies or increased review strategies which could be implemented in those situations? What will be done in five-years if North Dakota is over their projected emissions inventory? The SIP should provide a contingency plan to address these concerns.

Response: The following paragraph has been added to Section 11.3.
In addition, North Dakota commits to revise the implementation plan, including the reasonable progress goals, once RH SIPs from neighboring states become available and are approved by EPA, or if the unexpected or unforeseen occurs. This would include, but not limited to, projected future emissions reductions that do not occur, are distributed differently over an alternate geographic area, or are found to be incorrect or flawed. These revisions will be made within one year as required by §51.308(d)(4). North Dakota also commits to accelerate this revision schedule if the present RH SIP is found to be significantly flawed and the 2018 reasonable progress goals cannot be reasonably attained.

Comment 20: We request that ND note that there is a linkage between the PSD program, its visibility impacts, and the need to protect the 20 percent best visibility days. An adequate relationship between the SIP and ND's PSD program also helps ensure that new sources do not jeopardize the reasonable progress goals established by the RH SIP.

Response: A discussion of the linkage between the PSD program and Regional Haze Program will be added in Section 10 as Paragraph 10.7.

10.7 Prevention of Significant Deterioration

In North Dakota, new and modified existing major stationary sources triggering significance thresholds are analyzed under the Prevention of Significant Deterioration (PSD) permitting program. The PSD program rules are found in NDAC Chapter 33-15-15 and have been approved as a part of the North Dakota SIP by EPA. The PSD permitting program is a integral part of North Dakota's long term strategy for meeting its regional haze goals.

Among other things, the PSD permit program is designed to protect air quality and visibility in Class I areas by requiring best available control technology (BACT) and involving the public in permit decisions. The PSD permitting process requires a technical air quality analysis and additional analyses to assess the potential impacts of emissions on soils, vegetation and visibility. The cumulative impacts of emissions subject to the PSD program will be evaluated to ensure there is no degradation from baseline conditions on the 20 percent worst days and the 20 percent best days.

Therefore, North Dakota's current PSD program ensures that visibility at the Class I areas will not be impacted by growth in stationary sources.