Comments on TransGas Development Systems LLC
Coal-to-Gasoline Plant, Mingo County, West Virginia
Draft Permit R13-2791

by

Sierra Club
Appalachian Center for the Economy and the Environment
Ohio Valley Environmental Coalition
Coal River Mountain Watch
West Virginia Highlands Conservancy

December 17, 2009*

*As corrected by *errata* submitted to the West Virginia Department of Environmental Protection, Division of Air Quality via electronic mail on December 18, 2009.

Table of Contents

I. Introduction

At a time when there is a growing realization of the economic and environmental risks posed by continued reliance on coal, TransGas Development Systems LLC ("TransGas" or "Applicant"), a New York-based company, aims to build a $3 billion coal-to-gasoline plant ("TransGas Facility") in Mingo County, West Virginia. The plant would be located on 63 acres of what is currently an active mountaintop-removal surface mining site, a few miles from the state's border with both Kentucky and Virginia. The site plan shows the proposed facility nestled between two valley fills, directly on top of two headwater streams.[1] Surface mining activities at the site would continue for approximately four more years, overlapping construction and possibly operation of the plant.[2] The permit materials do not discuss whether the concurrent operation of a mine (with the associated use of explosives) and an industrial plant on the same site would pose safety concerns for employees or others.

The TransGas plant would process more than 3 million tons of coal each year.[3] Although the Application is vague about where this coal will come from (stating that "[v]arious seams will be used upon determination that the seams are appropriate for the source's operation")[4], the company has publicly stated that it plans to primarily use "locally mined" coal from West Virginia and elsewhere in Appalachia.[5]

The TransGas plant would result in devastating impacts from mining and transport of 3 million tons of coal per year from this area. The mountains, streams, forests, and communities of Appalachia have already been ravaged by mountaintop removal mining. TransGas's demand for coal would further contribute to this harm, without necessarily contributing to coalfield jobs. As Senator Byrd recently stated, "[i]n recent years, West Virginia has seen record high coal production and record low coal employment."[6]

While not directly relevant to the draft permit to construct[7] ("Draft Permit"), the

---

[1] TransGas's Revised Redacted Application (submitted June 12, 2009) (hereinafter "Application"), Attachment E.

[2] *See* West Virginia Department of Environmental Protection, Division of Air Quality, Engineering Evaluation/Fact Sheet (hereinafter "Engineering Evaluation") at 8; Application, Attachment C at C1.

[3] Engineering Evaluation at 4.

[4] Application, Attachment L at L11.

[5] John McMurry, West Virginia Site Awaits Coal-to-Gas Plant, the Site Selection Energy Report, September 21, 2009 (statement of Aaron Daley, TransGas Director of Development); http://www.siteselection.com/theEnergyReport/2009/september/transgas/index.html.

[6] Senator Robert C. Byrd, Opinion Piece: Coal Must Embrace the Future, December 3, 2009; http://byrd.senate.gov/speeches/view_article.cfm?ID=563.

[7] West Virginia Department of Environmental Protection, Department of Air Quality, Permit to Construct, R13-2791, Issued to TransGas Development Systems, LLC, TransGas Coal to Gasoline Plant, Draft, October 22, 2009.

TransGas facility will also require massive amounts of water.[8] If TransGas has analyzed whether the plant can realistically meet its water needs from local resources, and what the impacts would be on the area's rivers and drinking water, it has not made any such analysis public.

Despite claims to the contrary by TransGas and its supporters, the proposed facility is anything but "clean." In addition to the harm that would be caused by extraction of the coal for the plant, the pollutants emitted at the TransGas facility would cause a wide variety of health and environmental impacts, including global warming.[9] The plant's particulate matter ("PM"), carbon monoxide ("CO"), volatile organic compound ("VOC"), sulfur dioxide ("SO_2"), hazardous air pollutants ("HAPs"), and carbon dioxide ("CO_2") emissions are of particular concern and have not been adequately evaluated. DEP does not operate any ambient air monitors for criteria pollutants in Mingo County, so it is not known whether air pollutant levels already exceed federal ambient air quality standards in Mingo County. But Wayne County, immediately adjacent to Mingo County, already exceeds federal ambient air quality standards for fine particulate matter ("PM2.5").[10] VOCs, including methanol, contribute to formation of ground-level ozone, or smog. The plant's emissions of methanol, a hazardous air pollutant subject to especially stringent control under the federal Clean Air Act, have also escaped a meaningful and thorough review. In addition, the plant would emit odorous emissions that have not been addressed in the Draft Permit or clearly described for the public.

Emissions of the greenhouse gas ("GHG") CO_2 are at the center of nationwide efforts to address the crisis of climate change, yet the West Virginia Department of Environmental Protection, Division of Air Quality ("DEP" or "Department") completely ignores this facility's huge contribution. Although TransGas has publicly represented that it plans to capture CO_2 and transport it by pipeline to oil recovery operations in Texas,[11] nothing of the sort is discussed or required in the Draft Permit.

The TransGas facility is eligible for approximately $600 million in tax subsidies, according to an investigation by the Charleston Gazette. Ted Boettner, director of the West Virginia Center on Budget and Policy, told the Gazette that the $600 million in tax credits would amount to $3 million per job if the facility creates the 200 permanent jobs it promises.[12] Thus, while many have expressed support for this plant due to the perception

---

[8] Exhibit 1, U.S. Department of Energy, National Energy Technology Laboratory, Emerging Issues for Fossil Energy and Water, at 19, Table 2-1 (estimating 10,500 gallons-per-minute needed for a reasonably sized indirect coal-liquefaction plant using eastern coal as proposed by TransGas); http://www.netl.doe.gov/technologies/oil-gas/publications/AP/IssuesforFEandWater.pdf.

[9] *See* U.S. Environmental Protection Agency, Particulate Matter, Health and Environment; http://www.epa.gov/particles/health.html; Physicians for Social Responsibility, Coal's Assault on Human Health; http://www.psr.org/resources/coals-assault-on-human-health.html.

[10] PM2.5 is particulate matter with an aerodynamic diameter of 2.5 microns or less.

[11] *See, e.g.*, TransGas Development Systems, Video; http://www.transgasdevelopment.com/index.php?option=com_content&task=view&id=21&Itemid=42

[12] Ken Ward, Jr., Coal Plant Could Get $600 Million, Charleston Gazette, December 14, 2008; http://www.wvgazette.com/News/200812130478.

that it will create jobs for West Virginians, the state should question whether this project is the best way to answer the region's economic woes. Surely the state can do better than one job for every $3 million of public money spent. As we discuss below, in light of impending carbon regulations and low-carbon fuel standards, investments in more sustainable industries, such as tourism and renewable energy, would better serve the state's interests. Such investments are likely to create more jobs in the long run than investments in fossil fuel-based industries – especially given the new regulatory regimes soon to be faced by greenhouse gas emitters such as TransGas.

For these reasons, and the many others discussed below, we urge the Department to deny the requested permit as contrary to the public interest, health, and welfare. Even if the Department disagrees that the permit should be denied, its foremost obligation is to ensure that any final permit it issues fully complies with state and federal air quality regulations. As written, the Draft Permit fails in this regard. By allowing TransGas to ignore or underestimate many sources of emissions in its effort to remain a "minor source" under the Clean Air Act, the Department puts the public health, environment, and the viability of the project at risk. The Department must thoroughly and accurately account for and regulate *all* of the plant's harmful emissions, including greenhouse gases, *before* approving it.

If the Department continues to process the application, it should prepare a revised draft permit that complies with state and federal New Source Review requirements for a major source of air pollution. The revised draft permit must be renoticed, and the public must have a full and fair opportunity to comment and request a hearing on the revised draft permit.

II. Citizen Groups' Interests

The groups submitting these comments together represent approximately 5,000 West Virginians, including many who live in or near Mingo County, where the facility would be located, and the coalfields from which the coal for the plant will be mined. In addition to joining in the technical and legal comments contained here, individuals who are members of these groups have submitted separate comments to personally express their views on the TransGas facility and how it will affect their lives.

Sierra Club is a national nonprofit organization of approximately 1.3 million members and supporters dedicated to the protection and preservation of the natural and human environment. The West Virginia Chapter of the Sierra Club has approximately 2,000 members and more than fifty members live in counties near the proposed facility. Sierra Club also has active Chapters in Virginia and Kentucky; these states also hold an interest in the TransGas Facility, which would be located no more than a few miles from their borders. Sierra Club and its members have a longstanding interest and expertise in the development and use of natural resources and in air quality issues nationwide.

The Appalachian Center for the Economy and the Environment is a regional law and policy organization whose mission is to protect Appalachian communities and the natural environment that supports them by enforcing and strengthening state and federal environmental laws and by forcing the region's extractive and polluting industries to internalize their costs; revitalize Appalachian communities by helping to develop and implement an environmentally responsible, sustainable economy in the region; and conserve and restore the wilderness for the common benefit of the people who live in and enjoy the region's forests, streams, rivers and mountains.

Ohio Valley Environmental Coalition, with approximately 1,500 members, has a mission to organize and maintain a diverse grassroots organization dedicated to the improvement and preservation of the environment through education, grassroots organizing and coalition building, leadership development, and media outreach.

West Virginia Highlands Conservancy is a nonprofit membership organization located in West Virginia. Established in 1967, it is one of the state's oldest environmental advocacy organizations and for the past four decades has been a leader in citizen efforts to protect West Virginia's land and water resources from the effects of illegal and irresponsible coal mining. Its headquarters are located in Charleston, West Virginia, and most of its approximately 1,800 members reside in West Virginia.

Coal River Mountain Watch, with approximately 500 members, has a mission to establish social, economic and environmental justice in the southern coalfields of West Virginia, to keep communities intact and to improve the quality of life in these communities.

III. Summary of Defects in the Draft Permit

The Draft Permit fails to comply with state and federal air quality regulations.

The most serious flaw is that the Department has erroneously allowed the plant to bypass the core requirements of the Clean Air Act that would otherwise protect against potential violations of ambient air quality standards and require that TransGas use the best available control technology ("BACT") to control emissions. Although the Department claims that the facility's emissions of regulated air pollutants would not trigger state and federal "major source" thresholds that would trigger BACT requirements, our review of the Application, Engineering Evaluation, and Draft Permit shows otherwise. The Draft Permit's potential-to-emit calculations for the TransGas Facility fail to accurately quantify emissions from a number of sources including:

- Criteria pollutant and HAP emissions from the emergency equipment;
- Particulate matter and reduced sulfur compound emissions from the sulfur solidification process;
- CO, VOC, and HAP emissions from the methanol synthesis process vents;
- VOC emissions from the cooling tower;
- VOC and HAP emissions from the truck loading rack;
- Entrained road dust particulate matter emissions from trucking of raw materials, products, and waste materials;
- Particulate matter emissions from coal handling;

- Particulate matter and HAP emissions from the gasification process.

When these emissions are accounted for, TransGas is a major source for purposes of New Source Review ("NSR") for VOCs, CO, PM, PM10, SO_2, and for HAPs, as discussed in our comments below. Thus, DEP must require TransGas to undergo the Prevention of Significant Deterioration ("PSD") permitting process, which would ensure that the facility will not interfere with the attainment or maintenance of applicable ambient air quality standards or cause or contribute to the violation of an applicable ambient air quality increment.[13] Without this process, and the associated ambient air quality modeling of emissions from the TransGas facility, neither DEP nor the public can know what the air quality impacts – or public health impacts – of this facility actually will be. Rather, the "minor source" designation allows the plant to be built without an adequate analysis of its air quality impacts.

Given the Applicant's public representations that the facility would be "clean," and its air emissions "safe," it should be willing to do the necessary air modeling to show that the facility's emissions would not be detrimental to local air quality, and to show that it is using the best available pollution control technology. These precautions are mandatory for a major source of air pollution, and, even as a minor source, DEP may require air modeling to determine what the facility's impacts on ambient air would be. *See* 45 CSR 13 §5.7 (authorizing DEP to require TransGas to demonstrate that the plant would not interfere with ambient air quality standards or increments, even if it does not make the determination that the plant is a major source)

The erroneous minor source designation is not the Draft Permit's only problem. Other issues include unachievable limits on emissions or operational parameters, insufficient monitoring, and the failure to address several criteria pollutants, *i.e.*, PM2.5, sulfuric acid mist ("H_2SO_4"), and total reduced sulfur, at all.

IV. The Draft Permit Is Not in the Public Interest

The Department's authority to issue an air permit for the TransGas Facility stems from the West Virginia Air Pollution Control Act, W.Va. Code §§ 22-5-1, *et seq.*, which states that it is the "public policy of this state and the purpose of [the Air Pollution Control Act] to achieve and maintain such levels of air quality as will protect human health and safety, and to the greatest degree practicable, prevent injury to plant and animal life and property, foster the comfort and convenience of the people, promote the economic and social development of this state and facilitate the enjoyment of the natural attractions of this state." The purpose of the Air Pollution Control Act is, among other things, to "provide a framework within which all values may be balanced in the public interest."[14]

The Department may not issue a permit for construction if it would "be inconsistent with the intent and purpose" of the Air Pollution Control Act.[15] Thus, in

---

[13] 40 CFR §52.21; 45 CSR § 14 (all citations to "CSR" refer to the West Virginia Code of State Rules).
[14] *Id.*

[15] *Id.*

addition to the specific technical problems identified below, the Department has an obligation to consider the whether a coal-to-gasoline plant will serve the public interest overall. The undersigned groups emphatically believe that it will not. There are a number of reasons that a $3 billion investment in this proposed fossil fuel facility, instead of investments in sustainable, green jobs, would be a step in the wrong direction for West Virginia.

The immense societal costs of mining three million tons of coal per year to feed this plant weigh heavily against the public interest. As explained by Professor Michael Hendryx of West Virginia University in a recent peer-reviewed study, coal mining costs Appalachians five times more in early deaths than the industry provides to the region in jobs, taxes and other economic benefits.[16] Deriving not only electric energy, but also transportation fuels, from coal would add to these costs.

Further, by ignoring the facility's emissions of greenhouse gases, the Department both ignores the broad scientific consensus that such emissions must be curbed to avoid catastrophic consequences, and fails to provide the public and other decision makers with an accurate picture of how TransGas would fare when these emissions are regulated. There is no longer any doubt that greenhouse gas polluters will have to find ways to limit their emissions. On December 7, 2009, the U.S. Environmental Protection Agency ("EPA") finalized its finding that CO_2, methane, and other greenhouse gases represent a significant threat to public health and welfare. Clean Air Act Section 202 specifically states that EPA "shall" (*i.e.*, must, not may) regulate dangerous pollutants once they are found to endanger public health or welfare. The EPA also recently held two national public hearings regarding a new rule that will address large stationary sources of greenhouse gas emissions, like the TransGas plant.[17] Yet, the Draft Permit and Engineering Evaluation read as if greenhouse gas emissions were not an issue. Nothing could be further from the truth, politically, economically, or morally. TransGas should not be permitted to ignore this pressing concern. As Senator Byrd recently stated: "The truth is that some form of climate legislation will likely become public policy because most American voters want a healthier environment. Major coal-fired power plants and coal operators operating in West Virginia have wisely already embraced this reality, and are making significant investments to prepare."[18] Yet, both TransGas and the Department have ignored this "reality."

The regulatory landscape for transportation fuels also bodes poorly for this plant's contribution to the West Virginia economy. While TransGas has heralded coal-to-liquid technology as the future of transportation fuels, a number of regulatory

---

[16] Michael Hendryx and Melissa M. Ahern, Mortality in Appalachian Coal-Mining Regions: The Value of Statistical Life Lost, 124 Pub. Health Reports 541 (July–August 2009); http://snipurl.com/tqau7 [www_wvpbmedia_com], accessed December 15, 2009; See also West Virginia University, WVU Healthcare, Health News, WVU Study Links Chronic Illness to Coal-Mining Pollution, March 25, 2008; http://www.health.wvu.edu/newsreleases/news-details.aspx?ID=844.

[17] *See* Fact Sheet, Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; http://www.epa.gov/NSR/fs20090930action.html.

[18] Senator Robert C. Byrd, Opinion Piece: Coal Must Embrace the Future, December 3, 2009; http://byrd.senate.gov/speeches/view_article.cfm?ID=563.

initiatives suggest that the country is moving in exactly the opposite direction. These initiatives aim to *decrease* the market share of high-carbon fuels derived from fossil fuels such as coal. Specifically, in 2007, Congress passed the Energy Independence and Security Act which mandated that transportation fuels sold in the United States include 15.2 billion gallons of renewable fuel by 2012 and 36 billion gallons by 2022.[19] The EPA is currently at work implementing this mandate, having issued a proposed rule in May 2009.[20] The Commonwealth of Kentucky, the third largest producer of coal in the United States, is also looking for a strategy to use renewable fuels for transportation. There, the Governor aims to have at least 12% of motor fuel comprised of biodiesel.[21] Eight Midwestern states have joined together to adopt a shared Energy Security and Climate Stewardship Platform.[22] This plan seeks to reduce the amount of fossil fuels used in biodiesel production by 50% in 2025 and to require that at biodiesel and other low-carbon fuels contribute to at least 50% of all transportation fuel.[23] Other signals also suggest that the market for coal-based gasoline is shrinking: in October, the United States Air Force decided to abandon its plans to support development of coal-to-liquids for jet fuel.[24] The gasoline produced by the proposed TransGas Facility would be highly carbon-intensive (i.e., producing more carbon dioxide over its life cycle than other fuels) and therefore disfavored under both a fuel standard regime that takes into account life-cycle carbon emissions, and a carbon cap-and-trade system. The Department and other agencies and decision makers considering the economic wisdom of building this plant should take these policies into account.

Although the Department appears to view its mission very narrowly, it has an obligation to consider these issues, and ensure that permitting this plant is consistent with the state legislature's goals of promoting health, well-being and economic sustainability. In the public interest, it should exercise its authority under 45 CSR 13 §5.7 and deny the Draft Permit.

---

[19] *See* P.L. 110-140, § 202(a)(2)(B)(i)(I); the Act also aims to account for the "lifecycle greenhouse gas emissions" of such fuels. *Id.* § 202(a)(1).)

[20] 74 Fed Reg. 24,904 (May 26, 2009).

[21] Governor Steven L. Beshear, Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence, November 2008; http://www.energy.ky.gov/NR/rdonlyres/C3E2E625-AF3C-483D-955F-99FF57D74C64/0/FinalEnergyStrategy.pdf, accessed December 11, 2009; *see* also KRS 152.7290, 2009.

[22] *See* Energy Security and Climate Stewardship Platform for the Midwest 2007 http://www.midwesterngovernors.org/resolutions/Platform.pdf.

[23] *Id.* at 10.

[24] Energy & Environment News, Coal: Airforce Abandons Effort to Spur CTL Development, October 21, 2009; http://www.eenews.net/eenewspm/2009/10/21/4/.

V. The Department Must Release Information that is "Indispensable or Essential to Determining Emissions" from the TransGas Facility for Public Review and Comment Prior to Issuing a Final Permit

Throughout the application process, TransGas has insisted on shielding crucial information from the public. This lack of transparency violates state and federal regulations and has made it impossible for the public to perform a thorough review of the Draft Permit and its underlying assumptions. Under West Virginia law, "emissions data" may not be withheld pursuant to claims that it constitutes confidential business information ("CBI").[25] Section 4 of 45 CSR 31B provides that "[i]nformation or data that is indispensable or essential to determining emissions ... will be considered emission data and thus non-confidential."[26] As explained in Sierra Club's February 11, 2009 letter, key pieces of information that are "indispensable or essential to determining emissions" were redacted in the TransGas Application. Although we appreciate that some of the redacted information was subsequently disclosed, the final Application continued to claim CBI for information essential to verifying the plant's minor source status. In particular, TransGas redacted the entire methanol-to-gasoline ("MTG") process flow diagram and supplemental process description as well as certain information necessary to determining emissions from the methanol synthesis process, along with other important information. Without a process flow diagram for the MTG system that lays out its battery limits and process flows, and identifies fugitive components, it is not possible to evaluate the accuracy of the Draft Permit's emission estimates.

The Department's unsupported conclusion that the information claimed CBI is "not require[d] to verify [emissions estimates] to an acceptable level" does not justify withholding this information from the public. Although TransGas's contractor Uhde claimed in some instances that it did not need to provide certain data (*e.g.*, the burner capacity for the gasifier) because it used data from experience with a similar plant located in Spain using Uhde's process instead, the missing data are still necessary to verify emissions estimates. There is no assurance that the methods for testing or calculating emissions in Spain comply with this country's standards for doing so.

VI. The Application is Inconsistent and Incomplete

Even putting aside the large blocks of redacted information, the application materials provided by TransGas are incomplete and riddled with inconsistencies. The Department should have required TransGas to clarify its assumptions and calculations, and provide all the information requested on the application forms. Without such information, it is impossible to verify the Applicant's claims about the plant's potential emissions or to include the needed limitations in the permit to enforce minor source emissions levels.

The Application also failed to include a process and instrument diagram ("P&ID") or an accurate inventory of fugitive components by process unit. Without the

---

[25] 45 CSR 31B-1.

[26] *Id.* § 45-31B-4.1; see also 40 CFR § 2.301(incorporated by W.Va. Code § 45-31B-6).

above information, neither DEP nor members of the public can accurately verify emission estimates or evaluate proposed permit conditions for practicality and enforceability.[27]

The Application also fails to include information sufficient to determine whether the assumptions the Applicant makes about equipment performance are valid. Although both the Applicant and DEP have relied on vendor guarantees in their assumptions about the plant, the Applicant has repeatedly asserted that the design of various process units is not finalized, and therefore it has not yet determined which operating parameters are necessary to meet the manufacturer's warranty.[28] The Department cannot simply take TransGas's word that it will self-enforce all parameters necessary to maintain the warranty for each process. Rather, it should require TransGas to provide the necessary information to include appropriate parameters as enforceable permit conditions.[29] Similarly, much of Attachment M is left blank because manufacturers have not been selected for the flare, air condenser pollution control, and other pollution control equipment,.[30]. As such, the Department cannot rely on non-existing "vendor guarantees" for control efficiencies.

Further, the documents provided by the Applicant contain numerous inconsistencies, making it unnecessarily difficult to review the provided information. For example, the summary table provided in Attachment N is inconsistent with the Attachments 1 through 3 to Task Order 1 authored by Uhde.

It is also worth mentioning that significant portions of the Application are printed in such small, smudged type as to be illegible, *e.g.*, the plot plan and process flow diagrams.[31]

---

[27] Since published factors for natural gas combustion are generally provided on the basis of one pound of pollutant per standard cubic foot of natural gas consumed, any one of the first four fields is necessary to determine the emissions associated with year-round combustion of natural gas to maintain a pilot flame on the flare.

[28] *See*, *e.g.*, Application, Attachment L at L21: "This unit is specifically designed for each process and final design has not been completed. Operating ranges and maintenance procedures will be identified during final design of each unit within the system. The procedures as identified will be followed." See also id. at L25, L29, L33, L37, L41, L45, etc. (same language).

[29] *See* 45 CSR § 13-5.4: "The application shall contain sufficient information as, in the judgment of the Secretary, will enable the Secretary to determine whether the source construction, modification, or relocation will be in conformance with the provisions of any applicable rules promulgated by the Secretary."

[30] *See*, *e.g.*, Attachment M: Air Pollution Control Device Sheet (Flare System): maximum capacity of the flare; flare height and flare tip inside diameter; number of pilot lights and rating; natural gas flow rate to flare pilot flame per pilot light; characteristics and composition of the waste gas stream to be burned; temperature and heating value of the waste gas stream; and maximum mass flow rate to the flare.

[31] *See* Application, Attachment F; Engineering Evaluation, Attachment A.

VII. The Department's Decision to Permit the Facility as a "Minor Source" of Criteria Air Pollutants and HAPs Is Based on a Faulty and Incomplete Analysis of the Facility's Potential-to-Emit

The Clean Air Act requires that proposed "fuel conversion plants," such as the TransGas Facility, [32] obtain a construction permit under the Act's PSD program unless the plant has a "potential-to-emit" of less than 100 tons per year for each regulated criteria air pollutant, rendering it a "minor source."[33] A source's "potential to emit" is defined as "the *maximum capacity* of a stationary source to emit a pollutant under its physical and operational design."[34] While a plant's "design" can include air pollution control equipment and restrictions on hours of operation or on the type of amount of fuel combusted, stored or processed, such limitations can only be treated as part of a plant's design if the effect it would have on emissions is enforceable as a practical matter.[35] To be enforceable as a practical matter, permit conditions must restrict operations or production; unless an emissions source is subject to a continuous emissions monitoring system ("CEMS"), blanket emission limits do not suffice.[36] Moreover, a limit on production or operation is practically enforceable only if the permit also includes recordkeeping requirements that allow the permitting agency to verify the source's compliance with its limits on at most a monthly basis.[37]

Major sources of HAPs are those with the potential to emit 10 tons/year or more of any single regulated HAP, or 25 tons/year or more of any combination of HAPs.[38] Major sources of HAPs are required to comply with Maximum Achievable Control Technology ("MACT") regulations that must, where achievable, eliminate such emissions entirely.[39] New sources subject to MACT must achieve emissions reductions that are at least as

---

[32] EPA has historically defined fuel conversion plants as "plants which accomplish a change in state for a given fossil fuel. The large majority of these plants are likely to accomplish these changes through coal gasification, coal liquefaction, or oil shale processing." *See* Letter from G. Worley, Chief, Air Permits Section, U.S. Environmental Protection Agency Region 4, to V. Barringer, South Carolina Department of Health and Environmental Services, June 4, 2007; http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/fuelcon2.pdf.

[33] 40 CFR § 52.21(b); 45 CSR §§ 14-2.43, 14-3.

[34] 40 CFR § 52.21(b)(4); 45 CSR § 14-2.58; 45 CSR § 13-2.19; *see* also USA v. Louisiana-Pacific Corp., 682 F. Supp. 1141, 1157 (D. Colo. 1988): The concept of potential-to-emit "refers to the maximum emissions a source can generate when being operated within the constraints of its design."

[35] U.S. Environmental Protection Agency, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1980 (hereinafter "NSR Manual"), at A.11.

[36] Exhibit 2, U.S. Environmental Protection Agency, Memorandum from T. Hunt & J. Seitz Re: Guidance on Limiting Potential to Emit in New Source Permitting (hereinafter "Guidance"), at 7-8; http://www.epa.gov/Region7/programs/artd/air/title5/t5memos/lmitpotl.pdf.

[37] NSR Manual at A.5–A.8.

[38] 42 U.S.C. § 7412 (a)(1); § 7412(b); 40 CFR Part 63; 45 CSR 34 (adopting 40 CFR Part 63 by reference); 45 CSR 13-15.

[39] 42 U.S.C. § 7412(d)(2).

stringent as "the emission control achieved in practice by the best controlled similar source."[40]

The Department intends to permit the proposed new facility as a minor source under the federal Clean Air Act claiming that its potential-to-emit is less than 100 ton/yr for each regulated pollutant and less than 10 tons/year of any single regulated HAP or 25 tons/year of any combination of HAPs. The TransGas Facility thus avoids the more stringent requirements of PSD permitting and of Regulation 14 in the Code of State Rules that would apply to a major source, and the MACT regulations. A review of the Application, Engineering Evaluation, and Draft Permit reveals that this conclusion is flawed: the TransGas Facility would, in fact, be a major source of VOCs, PM, PM10, CO, SO_2, and HAPs. A comparison of the Department's estimates and our revised estimates of the facility's potential-to-emit ("PTE"), based on revised assumptions and quantification of a few previously omitted emission sources (discussed in the comments below), is provided in the following table.

Criteria Pollutant and HAP Potential-to-Emit
(tons/year)

		Emissions in Excess of DEP's PTE[b]							
Pollutant	DEP's PTE[a]	Sulfur Flaking[c]	Cooling Tower	Haul Roads	Coal Handling	Methanol Synthesis Unit	Flare	Revised PTE[b]	Major Source?
PM	75.29	3.38	+++	23.46	3.79			118.07	YES
PM_{10}	57.20	0.23	+++	7.71	1.80			67.02	YES[+++]
VOC	41.90		56.69			31.37	+++	129.96	YES
CO	67.28						+++	67.28	YES[+++]
SO_2	91.80						102.6	194.40	YES
HAPs	4.30		8.62			31.37		44.29	YES

a Engineering Evaluation, Tables 2 and 3 at 16-17.
b As discussed in the following comments. ***These estimates are only for emissions that could be quantified with the information available and in the time allotted for public comments;*** as discussed below and in the Technical Appendix, emissions are likely to be even higher for each pollutant if all emissions sources are taken into account and errors corrected.
c Highly conservative: assumes 99.5% control, although no control was identified in Draft Permit.
[+++] Indicates emissions that were not quantified in this comment letter but can be expected to be substantial based on the comments below.

This table shows that when emissions of a number of sources are included and/or revised, the TransGas Facility would be a major source for all criteria pollutants.

Other coal-to-liquids projects on the scale of the TransGas Facility, which would process 3.0 million tons per year ("MMtpy") of coal, have all been permitted as major sources for purposes of NSR review. For example, the Medicine Bow Fuel & Power LLC coal-to-liquids proposal in Wyoming, a similar source that will convert 3.2 MMtpy[41] to gasoline using a methanol-to-gasoline process, will be permitted as a major source of all

[40] 42 U.S.C. § 7412(d)(3).

[41] (8,700 tons/day) × (365 days/year) / (1,000,000 tpy/MMtpy)= 3.2 MMtpy

PSD-regulated pollutants.[42] Similarly, Southeast Idaho Energy's coal-to-fertilizer project, which would process up to 0.8 MMtpy[43] of a coal/petcoke blend, is being permitted as a major source.[44] The coal-to-substitute natural gas ("SNG") Kentucky NewGas proposal, which would process 4.9 MM tpy of coal[45], and the Illinois Power Holdings application for a coal-to-SNG plant, which would process 1.0 MMtpy[46] of coal, are also permitted as major sources.[47] Each of these applications was submitted to the Department in conjunction with Sierra Club's April 21, 2009 letter, and is incorporated by reference here.

The Department should revisit its estimates of the TransGas Facility's potential to emit criteria pollutants and HAPs, and require the Applicant to comply with the preconstruction requirements for major sources found in 45 CSR 14 and 40 CFR § 52.21, and 40 CFR Part 63. The following discussion details the errors and omissions in the Department's analysis and supports the revised figures in the above table.

A. The Draft Permit Omitted Several Emission Sources from the Facility's Potential-to-Emit

The Draft Permit fails to account for emissions from the following sources.

1. Criteria Pollutants and HAP Emissions from the Emergency Equipment

The emission calculations provided by the Applicant fail to account for emissions from the emergency equipment, *i.e.* diesel generators and firewater pumps that would be installed at the TransGas Facility to provide backup power in case of electric power interruptions. This type of emergency equipment is typically diesel-powered and must be tested on a regular basis, typically once per month, to ensure reliability. Criteria pollutant and HAP emissions from testing this emergency equipment must be included in the facility's potential to emit.

The Kentucky NewGas facility, for example, will operate four 1.5-MW diesel generators and one 300-hp diesel-powered firewater pump. Annual emissions from this equipment, assuming 500 hours of operation per year, are estimated at 46.1 tons/year NOx,

---

[42] Wyoming Department of Environmental Quality, Medicine Bow Fuel & Power, LLC, Permit No. CT-5873, March 25, 2009.

[43] (2,300 tons/day) × (365 days/year) / (1,000,000 tpy/MMtpy)= 0.8 MMtpy

[44] Idaho Department of Environmental Quality, Air Quality Permit to Construct No. P-2009.127, Southeast Idaho Energy, LLC, Facility ID No. 077-00029, rev. November 30, 2009; and Southeast Idaho Energy, LLC, Application for Authorization to Construct the Power County Advanced Energy Center, April 2008.

[45] Kentucky NewGas, Air Permit Application for New SNG Production Facility, Central City, KY, PSD/Title V Air Permit Application, December 2008 at Table 5-2.

[46] (2,630 tons/day) × (365 days/year) / (1,000,000 tpy/MMtpy)= 1.0 MMtpy

[47] Illinois Department of Air Pollution Control, Power Holdings of Illinois, LLC, SNG Plant, Construction Permit - PSD Approval, NSPS Emission Units, Application No.: 07100063, I.D. No.: 081801AAF, 217/782-2113, October 26, 2009.

26.45 tons/year CO, 2.0 tons/year VOC, 1.51 tons/year PM10, and 0.11 tons/year SO_2.[48] Southeast Idaho Energy's coal-to-fertilizer project would operate a 2-MW emergency generator for the gasifier and a 500-kW emergency firewater pump burning No. 2 diesel fuel. Annual emissions from this equipment assuming 100 hours of operation per year are estimated at 2.0 tons/year NOx, 0.12 tons/year CO, 0.03 tons/year VOC, 0.01 tons/year PM10, and 0.06 tons/year SO_2.[49,50] Clearly, emergency standby equipment can contribute a substantial amount of criteria pollutant emissions which must be accounted for in the facility's potential-to-emit.

Because these emergency units are typically diesel-powered, they emit diesel particulate matter, a known carcinogen, and other hazardous air pollutants which must be accounted for in the estimate of HAP emissions from the TransGas Facility.

2. Particulate Matter and Reduced Sulfur Compound Emissions from the Sulfur Solidification Process

According to the Engineering Evaluation, the facility's sulfur recovery unit ("SRU") would convert sulfur-containing compounds contained in waste gases to liquid elemental sulfur. Subsequently, "[t]he produced liquid sulfur is collected, degassed, and solidified."[51] Sulfur may be solidified as flakes, slates, prills, nuggets, granules, pastilles, and briquettes.[52] The Application indicates that the facility would produce 25,782 tons/year of elemental sulfur products in the form of flakes.[53,54] Yet, nowhere in the Application or the Engineering Evaluation is there a description of the sulfur solidification and flaking process or an estimate of the emissions produced by this solidification process or a discussion of any control technology to limit those emissions.

---

[48] Four 1.5-MW Generators: 45.8 ton/year NOx, 26.02 ton/year CO, 1.77 ton/year VOC, 1.49 $PM10_{total}$, 0.03 ton/year SO_2, and 0.0006 ton/year H_2SO_4 (Kentucky NewGas Application Table C-9.2).

One 300-hp Firewater pump: 0.31 ton/year NOx, 0.43 ton/year CO, 0.19 ton/year VOC, 0.02 $PM10_{total}$, 0.08 ton/year SO_2, and 0.0018 ton/year H_2SO_4 (Kentucky NewGas Application Table C-8.2).

[49] Idaho Department of Environmental Quality, Air Quality Permit to Construct No. P-2009.127, Southeast Idaho Energy, LLC, Facility ID No. 077-00029, rev. November 30, 2009; and Southeast Idaho Energy, LLC, Application for Authorization to Construct the Power County Advanced Energy Center, April 2008.

[50] 2-MW Diesel generator: 1.6 tons/year NOx, 0.09 tons/year CO, 0.03 tons/year VOC, 0.01 tons/year PM/PM10, and 0.05 tons/year SO_2 (Southeast Idaho Energy, LLC, Application Table 3-15);

500-kW Firewater pump: 0.4 tons/year NOx, 0.03 tons/year CO, 0.00 tons/year VOC, 0.00 tons/year PM/PM10, and 0.01 tons/year SO_2 (Southeast Idaho Energy, LLC, Application Table 3-16).

[51] Engineering Evaluation at 6.

[52] U.S. Environmental Protection Agency, Identification and Description of Mineral Processing Sectors and Waste Streams, Sulfur, Formed Sulfur.

[53] Application, Attachment N at N14: (2,669.53 kg/hour sulfur) × (2.205 lb/kg) × (8,760 hours/year) = 25,782 tons/year sulfur.

[54] Uhde, TransGas Development Systems, LLC, CTL Project, Process Description, rev. 00, September 2008, at 25.

Although TransGas has indicated that sulfur may be sold in either liquid or solid form[55], the Department may not permit the solidification of liquid sulfur without a characterization of the potential emissions associated with this process. Potential emissions of concern associated with the solidification of elemental liquid sulfur include particulate matter and reduced sulfur compounds such as hydrogen sulfide ("H_2S").

As shown in the Technical Appendix, Section I, the potential uncontrolled particulate matter emissions associated with drying and "flaking" liquid sulfur to the final product state, solid sulfur flakes, can be estimated at about 3,100 tons/year of $PM_{filterable}$ and 62.1 tons/year of $PM10_{filterable}$. If controlled by a 99.0% efficient control technology, the potential controlled process emissions can be estimated at 31.1 tons/year of PM and 0.6 tons/year of PM10. If controlled by a 99.5% efficient control technology, potential controlled process emissions can be estimated at 15.5 tons/year of PM and 0.3 tons/year of PM10. If controlled by a 99.9% efficient control technology, potential controlled process emissions can be estimated at 3.1 tons/year of PM and 0.1 tons/year of PM10.

The solidification process would also result in H_2S emissions from the degassed liquid sulfur. The Kentucky NewGas facility quantified reduced sulfur compound emissions from the solidification process for a total production of 192,720 tons/year of solid sulfur product at 0.78 tons/year of H_2S.[56] Scaled to the expected production of 25,872 tons/year at the TransGas facility, emissions of reduced sulfur contents can be estimated at 0.1 tons/year of H_2S.[57]

Further, storing the sulfur flakes would require a storage container where the solid sulfur would be temporarily stored before being loaded onto trucks for off-site transport. This surge container must be equipped with a bin vent filter to reduce particulate matter emissions. Based on calculations for the Kentucky NewGas facility, controlled PM10 emissions from the bin vent filter can be estimated at 0.07 tons/year provided TransGas installs a bin vent filter with the same level of performance.[58]

Further, the Draft Permit's estimates of particulate matter emissions from transfer points and conveyors fail to account for emissions associated with loading the solid sulfur flakes onto trucks for off-site transport.[59] The Application indicates that the Project would produce 2,669.53 kilograms per hour of sulfur. As detailed in Technical Appendix Section II, assuming a moisture content of 0.25% for the solid sulfur flakes and an 80% control efficiency, emissions from loading trucks with solid sulfur flakes can be estimated at 0.2 tons/year of PM and 0.1 tons/year of PM10.

---

[55] *Id.*

[56] Kentucky NewGas Application at Table C-16-1.

[57] (TransGas: 25,782 tons/year S) / (Kentucky NewGas: 192,720 tons/year S) × (Kentucky NewGas: 0.78 tons/year H_2S) = TransGas: 0.10 tons/year H_2S.

[58] (TransGas: 25,782 tons/year S) / (Kentucky NewGas: 192,720 tons/year S) × (Kentucky NewGas: 0.56 tons/year PM10) = TransGas: 0.07 tons/year PM10.

[59] *See* Application, Attachment N at N13.

The Department must require the Applicant to submit a description of the sulfur flaking process, determine the efficiency of any proposed control technology, establish enforceable emissions limits (verified as BACT) and monitoring requirements, and include the sulfur solidification process and associated emissions in the Draft Permit's potential-to-emit calculations.

3. CO, VOC, and HAP Emissions from the Methanol Synthesis Process Vents

In calculating the facility's potential to emit, the Department estimated emissions associated with component leaks (fugitive emissions) from the methanol synthesis process and methanol storage, but omitted emissions associated with the methanol synthesis process vents during normal operation of the methanol production process.

There are two production processes currently employed to produce methanol – the low pressure methanol ("LPM") process by ICI and the low cost methanol ("LCM") process based on Syntex syngas generation. Although TransGas has not specified which methanol production process will be used, there are certain unit operations common to both processes. These include makeup gas ("MUG") compression, methanol production in a converter or reactor where gas is generated, suction or vacuum of recycle gas to the recycle compressor, and gas purging from the entire synthesis loop.[60] Guidance published by the EPA indicates that emissions can be generated as a result of these processes.[61] The Draft Permit must be revised to account for emissions of CO and methanol (VOC and HAP) associated with these processes.

4. VOC Emissions from the Cooling Tower

The Project includes a cooling tower with a circulating water flow rate of 308,167 gallons per minute ("gpm"). The cooled water is used in heat exchangers throughout the facility to cool hot process streams which contain elevated concentrations of CO, VOCs, H_2S, and other reduced sulfur compounds which can be summarized as total reduced sulfur ("TRS"). It is well known that leaks in heat exchangers result in the leakage of process fluids into the cooling water.[62] The volatile compounds in this leakage are emitted at the cooling tower.[63]

---

[60] *See* Application, Attachment L at L30.

[61] U.S. Environmental Protection Agency, EPA 453/R-93-017, Control of Volatile Organic Compound Emissions from Batch Processes (Draft), November 1993, at 3-4, 3-5, 3-14, and 3-21.

[62] U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, AP-42, Chapter 5.1, Petroleum Refining, January 1995; Texas Commission on Environmental Quality Technical Supplement 2: Cooling Towers (January 2008), p. A-19, http://163.234.20.106/assets/public/comm_exec/pubs/rg/rg360/rg36007/techsupp_2.pdf; *See, e.g.,* Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection, Alberta Research Council, November 2006, 7-10, http://www.arc.ab.ca/documents/Dial%20Final%20Report.pdf; Fugitive VOC-emissions measured at Oil Refineries in the Province of Västra Götaland in South West Sweden, 2003, http://www.spectrasyne.ltd.uk/ROSEVOCreport.pdf; Direct Measurement of Fugitive Emissions of Hydrocarbons from a Refinery, Journal of Air and Waste Management, 58:1047–1056, August 2008,

The Application and Engineering Evaluation estimated the PM and PM10 emissions from the cooling tower, but did not estimate the emissions of other pollutants.[64] Further, the permit conditions relating to the cooling tower are not enforceable as a practical matter, as discussed below.

The process units in the subject facility are similar to those found in petroleum refineries. The EPA has developed a widely used emission factor for VOC emissions from similar cooling towers, 0.7 pounds of VOCs per million gallons ("lb VOC/MMgal") of cooling water for a controlled cooling tower. Based on this emission factor, VOC emissions could be as high as 56.7 tons/year.[65] Controlled emissions of VOCs from the cooling towers plus VOC emissions from other sources (41.9 tons/year) equal 98.6 tons/year, just 1.4 tons/year shy of the major source threshold. Other unaccounted for sources of VOCs, discussed elsewhere in these comments, easily exceed 1 ton/year. Thus, the Project is a major source based on VOC emissions. Most VOCs emitted from the process would also be HAPs and must be accounted for in the facility's potential-to-emit.

5. VOC Emissions from the Wastewater Treatment System

Wastewater treatment systems at synthetic organic chemicals manufacturing (SOCM) plants and refineries are known to emit VOCs.[66] Yet, the Division's analysis make no mention of VOC emissions from the plant's wastewater treatment system, identified as an isolated block on the Process Flow Diagram. Engineering Evaluation, Attach. A. The applicant has simply answered "no" to the question of whether there will be emissions from the wastewater system, but has not provided any support for this claim. App., Attach. K, p. K1. Nor does it appear that the Division scrutinized this assertion. The Division must evaluate emissions from the wastewater collection and treatment system and include them in the total Potential to Emit for the facility.

To do so, the Division should require the applicant to provide numerical and schematic representations of the wastewater collection system. All wastewater collection system components potentially involving emissions, including drains, vents, process equipment and tank containment sumps, junction boxes, manhole access points, storage tanks (including sourwater surge tanks), wastewater storage basins and outlets, should have been qualitatively and quantitatively described and evaluated for VOC emissions.

---

attached as Ex. 10. SEPA, VOC Fugitive Losses:New Monitors, Emission Losses, and Potential Policy Gaps (2006), http://www.epa.gov/ttn/chief/efpac/documents/wrkshop_fugvocemissions.pdf.

[63] *Id.* at 5.1-15.

[64] Application, Attachment J, Table 1 and Engineering Evaluation at 13.

[65] VOC emissions from controlled cooling tower:
$(0.7 \text{ lb}/10^6 \text{ gal}) \times (308{,}167 \text{ gal/min}) \times (60 \text{ min/hr}) \times (8{,}760 \text{ hr/yr}) / (2{,}000 \text{ lb/ton}) = 56.7 \text{ ton/yr}$.

[66] *See* Standards of Performance for New Stationary Sources: Volatile Organic Compound Emissions From the Synthetic Organic Chemical Manufacturing Industry Wastewater - Supplement to Proposed Rule, 63 Fed. Reg. 63,988 (Dec. 9, 1998); *see also* 40 CFR 60 Subpart QQQ—Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems; Standards of Performance for New Stationary Sources - VOC Emissions From Petroleum Refinery Wastewater Systems, 53 Fed. Reg. 47,623 (Nov. 23, 1988).

B. The Draft Permit Underestimates Emissions from Several Emission Sources

As discussed in the following comments, the Draft Permit underestimates a number of emission sources based on information provided by the Applicant.

1. Entrained Road Dust Particulate Matter Emissions from Trucking of Raw Materials, Products and Waste Materials

The Draft Permit's estimates of potential entrained road dust particulate matter emissions from trucking of raw materials (coal and limestone), products (sulfur, gasoline, LPG, and miscellaneous), and waste products (ash/aggregate and filter cake) are considerably underestimated for the following reasons.

First, the Draft Permit restricts the length of the on-site paved road to 0.11 miles for delivery of raw materials and removal of waste products and to 0.45 miles for removal of products, which results in an on-site roundtrip length of 0.22 miles for delivery of raw materials and removal of waste products and 0.9 miles for removal of products, respectively.[67] Yet, the calculations supporting the emission calculations in the Draft Permit only account for one leg of the haul trucks' roundtrips within the facility. In other words, the Draft Permit only accounts for truck travel to *or* from the facility (0.11 miles and 0.45 miles) but not for the entire length of the roundtrips on site (0.22 miles and 0.9 miles).[68] Thus, the Draft Permit's estimates for entrained road dust emissions of 14.44 tons/year of PM and 2.81 tons/year of PM10 must be revised to account for truck travel on the second leg of the roundtrip within the facility.

Second, the Draft Permit failed to account for the potential removal of gasoline and LPG by truck rather than by railcar. The Draft Permit does not limit the amount of gasoline and LPG that could transported by trucks, rather it only restricts the total maximum annual throughput of both the railcar and the truck loading racks.[69] Thus, the Draft Permit must be revised to either a) include a limitation for the annual volume of gasoline and LPG to be removed by truck and revise the entrained road dust emission estimates accordingly or b) revise the entrained road dust emission estimates based on a worst-case scenario of 100% removal of gasoline and LPG with trucks.

Third, the equation used to estimate entrained road dust particulate matter emissions is proportional to the silt loading of the on-site road. The Applicant's emission estimates are based on a silt loading of the road of 8 grams per square meter ("g/m^2").[70] This assumption is not supported and is not sufficiently conservative. Review of the available literature, *i.e.,* AP-42 Section 13.2.1 for Paved Roads, suggests that the mean silt loading on industrial roads ranges from 8.2 to 292 g/m^2 with a maximum silt loading of 400 g/m^2 observed.[71] Thus, the silt content of 8 g/m^2 assumed by the Applicant is

---

[67] Draft Permit, Condition 4.1.4.9(b).

[68] Application, Attachment N at N4, N8, N12, and N14.

[69] Draft Permit, Condition 4.17.4(b).

[70] Application, Attachment N at N4, N8, N12, and N14.

[71] *See* AP-42, 13.2.1 Paved Roads, November 2003, Table 13.2.1-4.

likely too low. Further, the EPA stated that this range of data likely does not reflect the full extent of the potential variation in silt loading on industrial roads because of variations of traffic conditions and the use of preventive mitigative controls on the roads that were investigated. Therefore, the EPA concludes that "the collection and use of site-specific silt loading data is preferred and is highly recommended. In the event that site-specific values cannot be obtained, an appropriate value for an industrial road may be selected from the mean values given in Table 13.2.1-4, but the quality rating of the equation should be reduced by 2 levels."[72] Among the industries listed in this section of AP-42, coppers smelting may be the closest to the TransGas facility with a listed mean silt loading of 292 g/m^2.

Fourth, the Draft Permit's calculations for entrained road dust emissions from the on-site paved roads assume a control efficiency of 85% which are presumably achieved by using a water sweeper, a water truck, underbody truck wash, rumble strips or other tracking control measures, a speed limit of 15 mph and timely removal of any spilled materials. While these measures are extensive and highly commendable, it is questionable whether they would result in an 85% control efficiency. As mentioned above, the calculation of particulate matter emissions may have already included the effects of watering and other mitigation measures. Most other agencies estimate the maximum control efficiency that can be achieved on paved roads with similar mitigation measures at about 50%.[73]

As summarized in the table below, using the same methodology as the Applicant, emissions from vehicle travel on the on-site paved roads can be estimated at 37.9 tons/year PM and 7.7 tons/year PM10 based on a revised roundtrip length of on-site truck travel of 0.22 miles for delivery of raw materials and removal of waste products and 0.9 miles for removal of gasoline, LPG, sulfur and miscellaneous other by-products; the removal of 100% of gasoline and LPG via truck; and otherwise using all of the Applicant's assumptions (Scenario A). Based on more conservative assumptions, *i.e.*, a silt content of 100 g/m^2 and a 65% control efficiency, controlled entrained road dust emissions from vehicle travel on the on-site paved roads can be estimated at 456.7 tons/year PM and 92.9 tons/year PM10 (Scenario B). The Table below provides a comparison of the Draft Permit's emission estimates of entrained road dust PM and PM emission and the two scenarios with and shows the difference between these estimates.

[72] *Id.* at 13.2.1-10.

[73] *See*, for example, Kentucky NewGas Application at Table 19.4: 50% PM10 control efficiency from street sweeping; Western Regional Air Partnership, WRAP Fugitive Dust Handbook, November 15, 2004: 4-26% PM10 control efficiency from street sweeping, 40-80% PM10 control efficiency from minimizing trackout; >90% PM10 control efficiency from removing trackout as soon as possible. These control efficiencies are not additive because they address different sources or locations of fugitive dust on the paved road.

Entrained road dust particulate matter emission from trucking of raw materials, products, and waste products

	Draft Permit	**Revised Scenario A**	**Revised Scenario B**
Materials	coal, limestone, ash, sulfur, miscellaneous	coal, limestone, ash, sulfur, miscellaneous, gasoline, LPG*	coal, limestone, ash, sulfur, miscellaneous, gasoline, LPG*
% Gasoline and LPG removed via truck	0%	100%	100%
Silt content	8 g/m^2	8 g/m^2	100 g/m^2
Roundtrip distances raw materials and waste/ products	0.11 miles/ 0.45 miles	0.22 miles/ 0.90 miles	0.22 miles/ 0.90 miles
Control efficiency	85%	85%	65%
PM emissions	**14.4 tons/year**	**37.9 tons/year**	**456.7 tons/year**
PM10 emissions	**2.81 tons/year**	**7.7 tons/year**	**92.9 tons/year**

* assuming an average gross vehicle weight of 20 tons for the gasoline and LPG trucks

In addition to other sources of PM emissions from the facility, total emissions of particulate matter increase to 98.7 tons/year of PM and 62.0 tons/year of PM10 for Scenario A and to 517.5 tons/year of PM and 147.2 tons/year of PM10 for Scenario B.[74] Thus, even based on the Applicant's erroneous assumptions regarding silt content and control efficiency, emissions from the haul roads would bring total PM emissions to within 1.3 tons/year of the major source threshold of 100 tons/year. Adjusting either the control efficiency or the silt content to reflect more realistic values would result in exceedance of the major source threshold for both PM and PM10.

2. Particulate Matter Emissions from Coal Handling

The Draft Permit's estimates of potential particulate matter emissions from coal handling are underestimated because they are not based on representative coal moisture

---

[74] Scenario A:
PM: (75.22 tons/year) - (14.44 tons/year) + (37.9 tons/year) = 98.67 tons/year
PM10: (57.13 tons/year) – (2.81 tons/year) + (7.71 tons/year) = 62.02 tons/year

Scenario B:
PM: (75.22 tons/year) - (14.44 tons/year) + (456.69 tons/year) = 517.47 tons/year
PM10: (57.13 tons/year) – (2.81 tons/year) + (92.92 tons/year) = 147.23 tons/year

content in calculations that are dependent on moisture content. (Particulate matter emissions from coal handling increase with decreasing coal moisture contents.)

The Draft Permit does not contain a minimum limit for coal moisture content. Thus, all calculations from coal material handling must be based on a worst-case scenario. The Applicant has indicated that it would use locally mined coal from West Virginia and elsewhere in Appalachia. For calculation of particulate matter emissions from coal handling TransGas assumed a coal moisture content of 5% by weight, which is not representative for the type of coal the Applicant proposes to burn. Review of the U.S. Geological Survey COALQUAL database indicates that the as-received moisture content of coal mined in West Virginia ranges from 0.4% by weight to 32.3% by weight with an average of 3.4% by weight. Almost 90 percent of samples of West Virginia coal have an as-received moisture content of less than 5% by weight. Samples from Mingo County range from 1.8 to 5.2% by weight with an average of 3.3% by weight. Since coal mining and hauling companies experience increased transportation costs for coal with higher moisture contents (due to the extra weight of the water), they have a financial incentive to keep the moisture content of the coal as low as practicable. Thus, use of the 5 % moisture content is unlikely to occur in practice, and certainly does not represent a worst-case scenario.

Using a more realistic coal moisture content of 3.5 percent for the emission calculations and otherwise keeping the Applicant's assumptions results in emission estimates of 9.39 tons/year PM and 4.47 tons/year PM10 compared to the Draft Permit's assumptions of 5.6 tons/year PM and 2.67 tons/year PM10 as summarized below.[75]

Emission Source	**Control Efficiency**	**PM Emissions (tpy)**	**PM10 Emissions (tpy)**
TCP1	50%	1.27	0.60
TCP2	50%	-	-
TCP3	80%	0.51	0.24
TCP4	80%	0.51	0.24
TCP5	80%	0.51	0.24
TCP6	80%	0.51	0.24
TCP7	50%	1.27	0.60
TCP8	50%	1.27	0.60
TCP9	50%	1.27	0.60
TCP10	80%	0.51	0.24
TCP11	50%	1.27	0.60
TCP12	80%	0.51	0.24
Total		**9.39**	**4.47**

3. Particulate Matter and HAP Emissions from Gasification Process

TransGas has assumed that antimony, arsenic, beryllium, chromium, cobalt, lead, manganese, nickel, and selenium metals and their compounds would remain in the slag produced in the gasification process and has indicated that there will be no emissions of

[75] Application, Attachment N at N3.

these metal compounds.[76] This is incorrect. During gasification coal is heated to a point of smelting and not combustion. This smelting produces a partially-vitreous, molten product called "slag", and it also produces "flyash."[77] By definition slag is a liquid while flyash is fine particulate.

The flyash has three possible trajectories in gasification: it may contact and coalesce with the slag as indicated by Uhde, it may contact and not coalesce with the slag, or it may not contact the slag at all. The last two scenarios are contradictory to Uhde's claim and would result in the emission of flyash containing metals, metal oxides, and metal sulfides to the atmosphere.

Eventually, molten slag flows down the bottom of the gasifier to a slag tap to the quenching water bath. However, there is a period when the slag tap is closed when molten material containing metal oxides, metal sulfides, and elemental metals is being heated and these substances are released as air pollutants. Moreover, the slag taps are prone to clogging[78] allowing molten metal to just sit and release emissions. Also, the quenching section contains gases[79] that are displaced when the slag tap is opened so that these gases can escape when the slag is removed such as when TransGas places slag in a knockout drum during pressure relief of the gasifier.[80] A recent study indicates that regardless of the slag tap opening radius (the interfacial area across which mass and transfer occur during slag wasting), the mole fraction of volatiles in the quench tank gas was approximately 0.16, *i.e.*, that 16 mol% of the gas in the quench tank is volatile and easily released to atmosphere during emptying of the quench tank.[81] The Draft Permit should be revised to estimate emissions of metals, metal oxides, and metal sulfides from the gasification process.

4. Criteria Pollutant and HAP Emissions from Flaring

The Department's estimate of emissions from the flaring of raw syngas from the gasifiers assumes that the flow rate of raw syngas to the flare is 100,000 cubic meters under normal conditions per hour ("m^3n/hour") per gasifier[82] (4,464 kmol/hour/gasifier[83]).

---

[76] Application, Attachment N, Attachment 1 "Response on DEP Questions" at 10. It should be noted that although mercury was included in the list of metals for which Uhde dismissed the possibility of emissions from the gasification process, emissions from mercury were nonetheless calculated at 9 of the same document.

[77] Lawrence J. Shadle, Peter L. Rozelle, Victor K. Der, The Partitioning of Particles Between Slag and Flyash During Coal Gasification, 2007 Gasification Technologies Conference, Slide 10; *see also* Electric Power Research Institute (EPRI AP 3290), H-Coal and Coal-to-Methanol Liquefaction Processes: Process Engineering Evaluation (Nov. 1983).

[78] Hsu, Heng-Wen, Cheng-Hsien Shen, Armin Silaen, Ting Wang, Effect of Slag Tap Size on Gasification Performance and Heat Losses in a Quench-Type Coal Gasifier, Proceedings of the 24th International Pittsburgh Coal Conference, Johannesburg, South Africa, September 10–14, 2007, at 1.

[79] *Ibid.*

[80] Application, Attachment N, Attachment 1 "Response on DEP Questions" at 10 indicates that during pressure relief to the flare slag will be held in the knock out drum. This implies that slag will be transferred from the quench tank to a knockout drum.

[81] *Id.* at 10

[82] Application, Attachment N, Attachment 2 at 14.

This appears to be based on Permit Condition 4.1.5.5(e), which limits the volume of raw syngas sent to the flare from the gasifiers to 100,000 m^3n/hr. However, this assumption is not enforceable as a practical matter because the Draft Permit does not place a limit on the *duration* of each startup or the total number of startups per year. Thus, the criteria pollutant and HAP emissions from flaring of raw syngas could be considerably higher than assumed for purposes of determining emissions from the flare.

Further, Condition 4.1.5.5(e), *i.e.,* the flow rate of 100,000 m^3n/hour during startups is not technically feasible based on TransGas's production goals and would likely be exceeded. The Application provides evidence that TransGas intends to operate at higher flow rates than assumed by the Department. Specifically, the Applicant indicated a flow rate of syngas to the flare of 620 tons/hour and a total flow rate of 28,517 kmol/hour.[84,85] As such, it smacks of a permit condition that is used to establish minor source status but that will not be met once the facility is built. EPA refers to such permit conditions as "sham" permits, which subject the facility to federal enforcement actions.[86] Because the facility is expected to operate above the limitation on the flow rate, the Department cannot rely on it in limiting the potential to emit. ""Implicit in the application of [operational restrictions as a means of limiting emissions to minor source levels] is the understanding that they comport with the true design and intended operation of the project." *Id.* at 13.

For example, based on the indicated feed rate of 28,517 kmol/hr (62,869 lb-mol/hr), and assuming 30 startups per year, there is a potential for SO_2 to be emitted during startup of the gasifier alone at a rate of 102.6 tons/year per gasifier.[87] The Department should include this amount in the facility's potential to emit. The sulfur dioxide emissions from this source alone would put the facility into the major source category.

---

[83] (100,000 m^3n/startup) × (30 startups/ year/gasifier) × (year/30 hours of startups) × (kmol/22.4 m^3n) = 4,464 kmol/hour. It should be noted that the Applicant's calculations erroneously indicate a conversion factor of 22.4 kmol/m^3n when in fact the correct conversion is 22.4 m^3/kmol (the molar volume of an ideal gas at standard temperature and pressure); the calculations were performed correctly.

[84] Application, Attachment N, Attachment 1 at 15.

[85] (620 ton syngas/hour/gasifier) × (2,000 lb/ton) × (lb-mol/22.9 lb) × (0.453592 kg-mol/l-mol) = 24,561 kmol/gasifier/hour.

[86] Exhibit 2 at 10: "Where EPA can demonstrate an intent to operate the source at major source levels, EPA considers the minor source construction permit void *ab initio* and will take appropriate enforcement action to prevent the source from constructing or operating without a major source permit."

[87] The SO_2 emission rate is calculated as follows based on the molar concentration of elemental sulfur in the syngas of 0.17%, a syngas molar flow rate of 62,869 lb-mol/hr, 2 lb-mols of SO_2 generated per lb-mol of H_2S generated, and 1 lb-mol H_2S generated per lb-mol of elemental sulfur:

((0.17 lb-mol H_2S) / (100 lb-mol syngas)) × (62,869 lb-mol syngas/hour/gasifier) ×
(2 lb-mol SO_2/lb-mol H_2S) × (64 lb SO_2/lb-mol SO_2) × (1 hour/startup) × (30 startups/year) /
(2,000 lbs/ton) = 102.6 tons SO_2 per year per gasifier.

a) Emissions from Flaring Under Less-than-optimal Conditions

The Draft Permit requires a 99.5% combustion efficiency for CO.[88] Studies have shown that wind and other factors can reduce flare combustion efficiencies significantly. This means that, although facilities typically estimate flare efficiency at 98% to 99%, more pollution is actually being released to the environment instead of being destroyed during combustion.[89] Although flares may be able to reach a 98-99% efficiency under best-case scenarios – *i.e.*, a completely calm day at optimal heat rates – the potential-to-emit calculation must be based on the worst-case scenario. Accordingly, DEP should account for the fact that the flare will sometimes be operating under imperfect conditions and recalculate its emissions estimates. The "98%" destruction efficiency for CO is an overestimation and emissions of CO during startup will be higher than estimated by the Applicant.[90] The 99.5% efficiency for CO stated in the permit is unrealistic and does not have any support in industry practice.

Also, because the majority of SO_2 emissions come from the flare, and the estimate of SO_2 is less than 9 tons shy of the major threshold, even a small decrease in flare efficiency could put the facility over then major source threshold for SO_2 emissions. The Department should address the studies showing that flares typically will not be able to reach the indicated destruction efficiency all the time, and adjust its emissions estimates accordingly.

b) Emissions from Flaring during Malfunctions

One of the key purposes of a flare is to release off-gases during system upsets and unplanned outages, *i.e.*, malfunctions. The Department nevertheless claims that it did not need to include emissions from the flare during malfunctions because those emissions will be considered a permit violation.[91] EPA has made it clear that a permitting authority cannot simply put *expected* emissions in the category of violations and omit them from a potential-to-emit calculation. Rather, potential to emit must include *all* emissions associated with the plant as it is intended to operate. "[A] source must estimate its

---

[88] Draft Permit, Condition 4.1.8.2(b)(1).

[89] *See, e.g.,* Exhibit 3, T.R. Blackwood, An Evaluation of Flare Combustion Efficiency, Using Open-path Fourier Transform Infrare Technology, J. Air & Waste Manage. Assoc. 50:1714-1722, October 2000; Industry Professionals for Clean Air, Reducing Flare Emissions from Chemical Plants and Refineries – An Analysis of Industrial Flares' Contribution to the Gulf Coast Region's Air Pollution Problem," May 23, 2005, http://www.ipcahouston.org/files/IPCA_Flare_Report2005.pdf; Robert E. Levy, Lucy Randel, Meg Healy and Don Weaver, "Reducing Emissions from Plant Flares – Paper # 61," Industry Professionals for Clean Air, April 24, 2006, http://www.ipcahouston.org/files/IPCA_Flare_AWMA2006.pdf; University of Alberta, Flare Research Project, Interim Report, November 1996 - June 2000, December 1, 2000; Douglas M. Leahey, Katherine Preston and Mel Strosher, Theoretical and Observational Assessment of Flare Efficiency, 51 J. Air & Waste Manag. at 1610, 1616 (2001).

[90] Please see Technical Appendix, Section VII for a calculation of increased CO emissions.

[91] Engineering Evaluation at 16: "Emissions resulting from operational malfunctions shall be considered 'excessive' and considered a Compliance/Enforcement matter. It is not the policy of the DAQ to permit operational malfunctions (with associated emergency releases of pollutants) and quantification and inclusion of these emissions into a facility's potential-to-emit is not required (nor for most sources without a site-specific operating history considered practicable."

emissions based on the worst case scenario taking into account startups, shutdowns, *and malfunctions*."[92] If there is evidence of a "source's intent to operate at higher levels than those for which it is permitted," a minor source impermissibly allows a source to circumvent new source review requirements.[93] "Where EPA can demonstrate an intent to operate the source at major source levels, EPA considers the minor source construction permit void *ab initio* and will take appropriate enforcement action to prevent the source from constructing or operating without a major source permit." *Id.*

The Department's claim that emissions from malfunctions need not be included in a facility's potential to emit falls flat in light of the reality of the purpose and typical use of flares. It is well known that flaring emissions from malfunctions are known to make up a large portion of similar facilities' emissions. A 2004 report documents releases from large petrochemical plants during the source refinery's "start-up, shut-down, and malfunction" ("SSM") (*i.e.*, normal operation of flares).[94] This review of industry-filed reports showed that for some facilities, releases from SSM events were actually higher than total annual "routine" emissions reported to either EPA's Toxics Release Inventory ("TRI") or state emission inventories for the entire facility for the entire year. The report found that more than half of the 37 facilities studied had SSM emissions of at least one pollutant that were 25% or more of their total reported annual emissions of that pollutant. For ten of the facilities, upset emissions of at least one pollutant actually exceeded the annual emissions that each facility reported to the state for that pollutant. SSM emissions of CO from Exxon Mobil's Baton Rouge facility were almost three times its reported annual CO emissions. A recent industry article on integrated gasification combined cycle ("IGCC") plants, which utilize nearly identical coal gasification configuration similarly noted that "[d]ue to gasifier maintenance *and the tendency for process upsets,* SSM events for IGCC plants are *relatively frequent* . . . ."[95] Thus, malfunctions are a predictable – even if irregular – event, and should be included in the facility's potential to emit.

Many permits, issued across the U.S., include emergency flaring emissions in potential to emit calculations and establish limits for the flares.[96]

---

[92] Exhibit 4: U.S. Environmental Protection Agency, Region 2, Letter from Steve C. Riva, Chief to William O'Sullivan, Director, NJ Dep't of Env. Protection, dated February 14, 2006; *emphasis* added.

[93] Exhibit 2 at 11.

[94] Environmental Integrity Project, Gaming the System – How Off-the-Books Industrial Upset Emissions Cheat the Public out of Clean Air, August 2004; http://www.environmentalintegrity.org/pdf/publications/Report_Gaming_the_System_EIP.pdf.

[95] John Colebrook, *Coal Gasification, a Promising Technology,* Electric Power & Light, July 2008, http://www.elp.com/index/display/article-display/336306/articles/electric-light-power/volume-86/issue-4/generation/coal-gasification-a-promising-technology.html

[96] *See, e.g.,* Iowa Department of Natural Resources, Air Quality Construction Permit, Homeland Energy Solutions, Application, Technical Support Document at 8 ("All emissions listed in Table 4 above are stated at the BACT emission limits." A BACT limit is specified for the flares.); Bay Area Air Quality Management District, Permit Evaluation and Statement of Basis for the Major Facility Review for Air Liquide Large Industries, April 2009 and issued Permit; Mississippi Department of Environmental Protection, Information Relative to the Draft Title V Operating Permit, Permit Issuance, October 2008 for Denbury Onshore LLC, Little Creek Facility, at 1 ("After the addition of the emergency flare, the facility's potential to emit of 120.5 tons per year (tpy) of VOC's exceeds the

The suggestion that the lack of "site-specific" data excuses the Department from estimating flaring emissions from malfunctions rings hollow when most of TransGas's estimates have been made without "site-specific" data. Given that TransGas has looked to a coal gasification plant in Spain using Uhde's process for many of its assumptions, and there is data from the Spain plant on unplanned outages, TransGas and the Department could use this information to calculate expected emissions from malfunctions at the proposed TransGas facility.

These expected emissions from malfunctions must be included in the plant's potential to emit. The Department's plan to consider such emissions permit violations does not exempt them from the potential-to-emit calculation because "blanket restrictions" on emissions are not federally enforceable permit conditions unless bolstered by a production or operational limitation and accompanying recordkeeping requirements, or continuous emissions monitoring.[97] The Engineering Evaluation does not even estimate the frequency, duration, or emissions from emergency and upset conditions let alone limit these parameters; thus, expected emissions from malfunctions, which could be based on experience at the Spain plant, must be counted in the potential-to-emit.

EPA specifically addressed a facility's failure to address emissions from flaring malfunctions in a recent Order partially granting a petition to object to a Title V operating

---

Title V threshold of 100 tpy." "Based upon the potential to emit of this flare (*i.e.*, year-round operation at maximum design flowrate), the construction of the flare for this new source of emissions would be a de minimus modification per APC-S-2, not requiring a construction permit."); Indiana Department of Environmental Management ("IDEM"), Technical Support Document for an Exemption for Koch Pipeline Company, at 3 ("The assumption that the emissions could occur for 8,760 hours per year at multiple points along the pipeline would render the pipeline useless for its economic purpose (*i.e.*, transport of ammonia). Instead, the potential to emit was calculated based on the maximum number of flaring episodes anticipated along the pipeline."); IDEM, Technical Support Document for an Exemption, Koch Fertilizer Storage and Terminal Company, January 6, 2003 at 12 (calculation of emissions from 240 hr/yr of emergency flaring); IDEM, Notice of Decision, Koch Fertilizer Storage & Terminal Company, December 6, 2002 at 10 (calculation of emissions from 300 hr/yr of emergency flaring); Illinois Environmental Protection Agency, Construction Permit, NESHAP Source, NSPS Source, PSD Approval, for ConocoPhillips Wood River Refinery, May 15, 2006, at 11-12 (emission limits on debottlenecked flares); Montana Department of Environmental Quality ("MDEQ"), Guidance Statement, Oil & Gas Well Facilities and Calculating Potential to Emit, June 1, 2007; MDEQ, Air Quality Permit, Bear Paw Energy, Inc., Permit #2982-02, April 17, 2008, at 2 (PBE shall limit the hours of operation of the emergency flare to 1,800 hours during any rolling 12-month period. This will result in emissions from the emergency flare of less than 41.4 tons of sulfur oxides (SOx) and 45.8 tons of CO during any rolling 12-month time period.") and 6 ("In order to maintain potential emissions below major source threshold, use of the emergency flare is limited to 1,800 hours per year."); MDEQ, Air Quality Permit, Encore Energy Partners Operating, LLC, Permit 3300-02, Administrative Amendment, September 9, 2007, at 1 ("Encore shall limit the volume of gas routed to the emergency flare pit (5-EF) to 4.42 million standard cubic feet ("MMScf") of gas flaring during any rolling 12-month time period (ARM 17.8.749).") and 18 (calculations); MDEQ, Air Quality Permit, Permit 2619-19, May 27, 2004, at 13 ("SO_2 emission increases, due to upset conditions or discontinuance of the SRU, shall be offset by an equivalent rate from any other sources covered by this permit.").

[97] *Id.* at 3-5; *United States v. Louisiana-Pacific Corporation*, 682 F. Supp. 1122 (D. Colo. October 30, 1987) and 682 F. Supp. 1141 (D. Colo. March 22, 1988).

permit for the BP Whiting refinery in Indiana.[98] Like an application for a construction permit, the application for a Title V permit must include "*all* emissions of regulated air emissions." 40 C.F.R. § 70.5.(c)(3)(i) and (viii). In the BP Whiting order, EPA determined that the state agency had erred in failing to account for flaring emissions— including those resulting from malfunctions.[99] While the state permitting agency had argued that it was not required to consider emissions from flares because they were not considered "normal operation," EPA rejected this claim. It ordered the agency to either place a prohibition on such emissions that was legally and practically enforceable to keep emissions of pollutants below the NSR significance levels, or apply the NSR/PSD rules to the modification in question.[100] Similarly, the Department cannot discount emissions from flaring malfunctions at TransGas unless it includes a legally and practically enforceable condition to prohibit such emissions.

c) Emission Estimates for the Flare Are Not Supported by Practically Enforceable Permit Limitations

A plant's potential to emit can take into account "air pollution control equipment and restrictions on hours of operation or on the type or amount of fuel combusted, stored or process."[101] However, to properly restrict the potential to emit, limitations must be both federally and practically enforceable. "When permits require add-on controls operated at a specified efficiency level, permit writers should include, so that the operating efficiency condition is enforceable as a practical matter, those operating parameters and assumptions which the permitting agency depended upon to determine that the control equipment would have a given efficiency."[102] State law also requires that the Department impose "enforcement conditions which assure that all emission limitations contained within the permit are quantifiable, permanent and practicably enforceable."[103] The Applicant and the Department have relied on several assumptions, in addition to those discussed above, that are not accompanied by quantifiable, practically enforceable permit conditions.

For example, the assumption that concentrations of NOx in the off-gas will be 250 ppm is based on a purported "industry standard."[104] Yet, neither the Applicant nor the Department provides any supporting information to justify this rate. Nor is this assumption enforced by a permit limitation, monitoring, or reporting.

Further, the Draft Permit has not required that the flare be assisted. Without assistance, flare combustion efficiency decreases at heat contents less than 300 Btu/ft^3 and

---

[98] *In the Matter of BP Products North America, Inc. Whiting Business Unit*, Order Partially Denying and Partially Granting Petition for Objection to Permit, October 16, 2009; http://www.epa.gov/reg5oair/bptitlevorder20091016.pdf.

[99] *Id.* at 5-7, 17-19.

[100] *Id.*

[101] 40 C.F.R. §§ 52.21(b)(4).

[102] Exhibit 2 at 7.

[103] 45 CSR 13 §5.11.

[104] Engineering Evaluation at 11.

when the flare gas contains nitrogen, at heat contents less than 365 Btu/ft^3. Therefore, the assumed 98% destruction efficiency for CO is an overestimation and, thus, emissions of CO during startup may be higher than estimated by the Applicant.

5. VOC and HAP Emissions from the Methanol Synthesis Unit

The emission factors used by TransGas, *i.e.*, Synthetic Organic Chemical Manufacturing Industry ("SOCMI") to estimate methanol emissions associated with leaks from the methanol synthesis unit, *i.e.*, "average" emission factors, were adopted from an EPA leak detection protocol document. This document provides a number of different methods for estimating mass emissions from equipment leaks in chemical process units depending on varying levels of environmental protection. The DEP failed to verify that the selected "average" emission factors appropriately characterize potential fugitive emissions from the facility, which they do not. Moreover, EPA audits have shown that actual emissions from fugitive sources can be significantly greater than emissions estimates derived with the use of SOCMI average values.[105]

Had TransGas instead employed "screening ranges" *i.e.*, emission factors that allow for "some adjustment for individual unit conditions and operation," and thus "offers some refinement over the average emission factor approach," from the EPA leak detection protocol document rather than "average" emission factors, the facility would be a major source for HAPs as emissions of methanol would by far exceed 10 tons/year and the sum of all HAPs would exceed 25 tons/year. The table below summarizes methanol emissions from the various components based on "screening ranges" from the EPA leak detection protocol.

Component Type	**Service**	**Welded/ Unwelded**	**Screening Range Emission Factor** (kg/hour/ source)	**Uncontrolled Emissions** (kg/hour)	**Control Efficiency due to Monthly LDAR**	**Control Efficiency for Welding**	**Controlled Emission Rate** (tons/year)
Valves	Gas	0/25	0.2626	6.565	87%	0%	8.24
Valves	LL	0/40	0.0852	3.408	84%	0%	5.27
PRV	Gas	0/1	1.691	1.691	0%	0%	16.33
Connectors	Gas	75/20	0.0375	3.5625	0%	100%	0
Connectors	LL	120/30	0.0375	5.625	0%	100%	0
Compressor	N/A	0/0	1.608	0	0%	0%	0
Pump	LL	0/1	0.437	0.437	69%	0%	1.31
Sampling Connections	Gas	0/1	0.01195	0.01195	0%	0%	0.12
Sampling Connections	LL	0/1	0.01195	0.01195	0%	0%	0.12
						Total Methanol Emissions	**31.37**

[105] U.S. Environmental Protection Agency, Enforcement Alert, Volume 2, Number 9, October 1999, EPA 300-N-99-014; http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/emissions.pdf, accessed December 7, 2009.

6. Other Underestimated Emissions

Detailed analyses of other emissions that were underestimated by TransGas and the Department is included in Technical Appendix, Section VI.

Underestimated Particulate Matter Emissions

- The steady-state particulate matter (PM, PM10) emissions from the methanol-to-gasoline process are underestimated (Technical Appendix VI.1).
- The particulate matter (PM, PM10) emissions are underestimated because TransGas did not estimate emissions of ammonium sulfate and ammonium carbonate from the CO_2 wash column (Technical Appendix VI.2).

Underestimated NO_X Emissions

- The Applicant underestimated NO_X emissions from the flare because Uhde assumed a flare exhaust flow rate that is less than the actual flow rate to the flare (Technical Appendix VI.3).

Underestimated CO Emissions

- The steady-state CO emissions are underestimated because the Applicant underestimated emissions associated with the production of CO byproduct from the methanol-to-gasoline process (Technical Appendix VI.4).
- The fugitive CO emissions associated with gasification including scrubbing are underestimated because the Applicant assumed that the stream was composed of organic compounds only (Technical Appendix VI.5).

Underestimated VOC and HAP Emissions

- The steady-state VOC and HAP emissions from the methanol-to-gasoline process are underestimated because the Applicant did not estimate emissions of methanol and dimethyl ether ("DME") from this process (Technical Appendix VI.6).
- The VOC emissions from the proposed TransGas facility are underestimated because the Applicant did not estimate fugitive VOC emissions from leaking components in bottoms stream from the CO_2 wash column (Technical Appendix VI.7).
- The hazardous air pollutants, carbonyl sulfide and hydrogen cyanide, and the NSR-regulated pollutants, hydrogen sulfide and total reduced sulfurs, from the proposed facility are underestimated because the Applicant underestimated the flow rate of these pollutants in the syngas and inflated the control efficiency of the flare (Technical Appendix VI.8).

C. The Draft Permit Potentially Underestimates Emissions from Several Emission Sources

The Draft Permit contains a number of emission estimates based on unsupported assumptions and are potentially underestimated. The Draft Permit should be revised to provide support for all assumptions and, if necessary, revise the emissions estimates for the facility.

1. VOC and CO Emissions Associated with Equipment Leaks in Gasification Process

The Applicant has potentially underestimated emissions of VOC and CO from coal milling and drying. TransGas estimated emissions from the feedstock based on an Uhde "investigation of previous coal."[106] The Applicant did not supply this investigation of previous coal. It is unclear whether the VOC and CO content of the "previous coal" is representative of the coal that would be used by TransGas. Further, there is no indication that the test methods used in this investigation meet the standards of the EPA or the Department nor that the Department has reviewed and approved the test results for use in this Application as required by law.

2. VOC Emissions from the Methanol Storage Tank

The Draft Permit limits emptying and filling of the methanol storage tank, the so-called "turnover," to 350 times per year.[107] However, the estimates for VOC and HAP emissions from the methanol storage tank are based on only 30 turnovers.[108] Accounting for 350 turnovers, total annual emissions of VOC and HAPs are estimated at 0.95 tons/year compared to 0.25 ton/year based on 30 turnovers.[109] If the Draft Permit limit of 350 is a drafting error, the Department should correct it to ensure compliance with the estimated potential to emit.

VIII. The Department Must Directly Regulate and Evaluate the Impacts of PM2.5 Emissions from the TransGas Facility

The Department may issue a permit for construction of a stationary source only after evaluating all regulated air pollutants that the source would emit in a significant amount.[110] The promulgation of a National Ambient Air Quality Standard ("NAAQS") for fine particulate matter, also known as PM 2.5, on July 18, 1997 triggered the duty to apply the NSR requirements to fine particulate matter.[111] In issuing the final NSR PM2.5 implementation rule in May 2008, EPA stated that states are obligated to address direct PM2.5 and precursor emissions from both major *and minor* sources.[112] As

---

[106] Application, Attachment N, Attachment 2 to Task Order 1at 6.

[107] Draft Permit, Condition 4.1.7.3.a, Table 4.1.x.x(a) indicates a maximum number of turnovers of 350 per year and a maximum throughput of 700,000,000 gallons for Tank TK6 containing methanol.

[108] Application, Attachment N, TANKS4.09d output for methanol tank.

[109] *See* TANKS4.09d output in Technical Appendix.

[110] 45 CSR §§ 13-2.24.b (defining "stationary source"), § 13-8.3 (requiring publication of "the type and amount of air pollutants that will be discharged"); at 14-2.79 and 14-21.1.b.

[111] 70 Fed. Reg. 65,984, 66,043 (November 1, 2005); 45 CSR § 13-2.20.b (defining "regulated air pollutant" as "[a]ny air pollutant for which a national ambient air quality standard has been promulgated…").

[112] 73 Fed. Reg. 28,321, 28,344 (May 16, 2008).

such, the Department must directly assess and regulate PM 2.5 emissions from the TransGas Facility, even if it does not determine that it is a major source of PM2.5 or any other pollutant. Fine particulate matter poses serious health risks; by limiting it, the Department would protect the public health and save West Virginia substantial health care costs, as discussed below.

A. PM2.5 Emissions Have Significant Public Health Impacts

PM 2.5 emissions are widely known to cause significant public health and environmental impacts. According to the EPA, the PM2.5 fraction of particulate matter is distinguishable from the PM10 fraction, as the smaller particles pose the "largest health risks."[113] In fact, in a 1996 report on the need to revise the NAAQS for PM, EPA staff found that the epidemiological data more strongly supports fine particles as the surrogate for the fraction of PM most clearly associated with health effects at levels below the standards in place at that time.[114] Disturbingly, PM2.5 has been linked to premature death, in addition to aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions for asthma, emergency room visits, absences from school or work, and restricted activity days), changes in lung function and increased respiratory symptoms, and more subtle indicators of cardiovascular health.[115] The EPA also has identified lung cancer deaths, infant mortality and developmental problems (such as low birth weight in children) as possibly linked to PM2.5.[116]

Children are especially susceptible to the harms from PM2.5. According to the American Academy of Pediatrics, children and infants are among the most susceptible to many air pollutants, including PM2.5. Exposure to high levels of fine particulates impacts the ability of children's lungs to grow.[117] This damage is irreversible, and subjects children to greater risk of respiratory problems as adults. Children also have increased exposure compared with adults because of higher minute ventilation and higher levels of physical activity, and thus face serious health problems from PM2.5 pollution. This susceptibility is evidenced by a recent study of PM2.5 and asthmatic

---

[113] *See* U.S. Environmental Protection Agency, PM2.5 NAAQS Implementation, *available at* http://www.epa.gov/ttnnaaqs/pm/pm25_index.html; *see* also U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information, Staff Paper, July 1996, ("PM2.5 Staff Paper") at V-58 to V-77 (discussing health studies of fine versus coarse particles), http://www.epa.gov/ttn/naaqs/standards/pm/data/1996pmstaffpaper.pdf

[114] PM2.5 Staff Paper at V-77.

[115] Clean Air Fine Particle Implementation Rule, 72 Fed. Reg. 20586, 20586-20587 (April 25, 2007) (to be codified at 40 CFR Part 51).

[116] *See* National Ambient Air Quality Standards for Particulate Matter, Proposed Rule, 71 Fed. Reg. 2620, 2627 (January 17, 2006).

[117] *See* Statement of Katherine M. Shea, MD, MPH, FAAP, On Behalf of the American Academy of Pediatrics, Before the Clean Air Scientific Advisory Committee to the U.S. Environmental Protection Agency, Regarding National Ambient Air Quality Standards for Particulate Matter, http://www.cleanairstandards.org/wp-content/uploads/2005/04/aap-testimony-4705-3.pdf.

children in Detroit, which emphasizes "the continued need for enforcement of existing standards" regarding PM 2.5.[118]

Older adults also are particularly susceptible to PM2.5 because of their weaker lungs and hearts. For example, studies have suggested that serious health effects, such as premature mortality, are greater among older groups of individuals.[119] Older adults also are more likely than younger ones to have preexisting respiratory and/or cardiovascular conditions that become aggravated with exposure to PM2.5.[120]

The costs of PM2.5 pollution are staggering. The serious health impacts and accompanying costs resulting from PM2.5 pollution will burden not only individuals, but also the state through expenditure of public and employer health care dollars, lost productivity, and strains on the education system from missed school days. The benefits from the control of PM2.5, however, are significant. For example, a cost-benefit study completed by the EPA for the agency's recent revision of the 24-hour PM2.5 standard showed from $9 billion to $76 billion in health and visibility benefits, compared to a cost of $5.4 billion for achieving the standard.[121] In all, West Virginia will benefit greatly from protecting its citizens through stringent control of PM2.5.

B. The Draft Permit Does Not Adequately Address PM2.5

The Draft Permit is flawed because it fails to directly regulate or evaluate emissions of PM2.5 from the TransGas plant. Instead, 11 years after PM2.5 was designated as a criteria air pollutant that must be regulated under the Clean Air Act, the Department essentially ignores PM 2.5 emissions.

First, the Department failed to publish the amount of PM 2.5 that would be emitted at the source, as required by state law.[122]

In the Draft Permit itself, the Department's only mention of PM 2.5 is in footnote 1 to Appendix A, which states that, "[f]or the purposes of this permit, all PM10 emission limits are equal to PM2.5 emission limits." These purported "PM2.5 emission limits" are rendered meaningless by the Draft Permit's failure to require any PM2.5 monitoring. Moreover, there is no analysis of whether the controls required for PM10 also minimize PM2.5 (in filterable and/or condensable form). As a result, it is unclear whether the purported PM2.5 emission limits are achievable, and they are certainly not enforceable. The Department could potentially resolve this issue by including a permit provision that requires all PM10 to be considered equal to PM2.5 for monitoring,

---

[118] *See*, *e.g.*, T. Lewis, et al., Air Pollution-Associated Changes in Lung Function among Asthmatic Children in Detroit, Environ, Health Perspect at 113:1068–1075 (2005); http://www.ehponline.org/members/2005/7533/7533.pdf.

[119] *See*, *e.g.*, 71 Fed. Reg. at 2637.

[120] *Id.*

[121] *See* National Ambient Air Quality Standards for Particulate Matter; Proposed Rule, 71 Fed. Reg. 2620, 2627 (January 17, 2006).

[122] *See* 45 CSR § 13-8.3.

compliance, and enforcement purposes. However, because PM2.5 has different (and more severe) impacts on public health and requires different controls than PM10, it merits independent analysis. These distinctions are explained in more detail below.

C. The Department May Not Use PM10 as a Surrogate for PM2.5

The use of PM10 as a surrogate for PM2.5 is unacceptable as a matter of law and is not technically justified. PM2.5 and PM 10 are different pollutants that require different control measures. As the EPA has recognized, the "characteristics, sources, and potential health effects of larger or 'coarse' fraction particles (from 2.5 to 10 microns in diameter) and smaller or 'fine' particles (smaller than 2.5 microns) in diameter) are very different."[123] The agency has also found that "in contrast to PM10, EPA anticipates that achieving the NAAQS for PM2.5 will generally require States to evaluate different sources for controls, to consider controls of one or more precursors in addition to direct PM emissions, and to adopt different control strategies."[124] This difference is obvious in the nonattainment listings themselves as many counties are in attainment for PM10 but out of attainment for PM2.5. Even where PM10 is properly controlled and compliance with the PM10 NAAQS has been sufficiently demonstrated, substantial harms are likely to occur from remaining PM2.5 pollution.[125] Therefore, it is unlawful and unreasonable to pretend that PM10 is PM2.5.

IX. The Department Must Quantify Sulfuric Acid Mist Emissions

The Draft Permit did not estimate emissions of sulfuric acid mist ("H_2SO_4") from the facility. Sulfuric acid mist would be emitted from the Claus sulfur recovery unit, the Rectisol acid gas removal unit, the diesel-driven emergency equipment, the gasifier vent, and other sources. These emissions must be quantified, permit limits must be set, and enforceable permit conditions must be developed.

X. The Department Must Evaluate and Limit the Facility's Greenhouse Gas Emissions

Greenhouse gas emissions are another class of pollutants entirely ignored by the Department. Despite the nation's growing commitment to curbing greenhouse gas emissions that contribute to climate change, and pending federal regulation to do just that, neither the Department nor the Applicant has even disclosed the quantity of greenhouse gases that the facility is expected to emit.[126] Speaking to a reporter, the

---

[123] U.S. Environmental Protection Agency, National Air Quality Standards for Fine Particles: Guidance for Designating Areas: Fact Sheet (July 17, 1997), http://www.epa.gov/ttn/caaa/t1/fact_sheets/pmfact.pdf

[124] Clean Air Fine Particle Implementation Final Rule, 72 Fed. Reg. 20586, 20589 (April 25, 2007).

[125] *See*, *e.g.*, Exhibit 11, Highwood Order, at 23-24: finding that the vast majority of uncontrolled PM emissions will be in the smaller PM 2.5 size range.

[126] The EPA announced in September 2009 that it "expects soon to promulgate regulations under the Clean Air Act to control GHG emissions and, as a result, trigger PSD and Title V applicability requirements for GHG emissions." See Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Proposed Rule, 74 Fed. Reg. 55,292 (October 27, 2009).

permit author estimated that the facility would emit 3.6 million tons of carbon dioxide annually even if 25% of the carbon dioxide were recycled back through the facility.[127] It appears that these emissions would be released primarily from the CO_2 purification unit at emissions point C1.[128] No analysis of these emissions was provided to the public, however. The Draft Permit and Engineering Evaluation remain silent on this facility's massive contribution to the levels of greenhouse gases in the atmosphere – which scientists have established are already much too high for the safety of the planet and human health.

It is now undisputed that global climate change poses serious risks to human health the environment.[129] Important economic resources such as agriculture, forestry, fisheries, and water resources will also be affected by warmer temperatures, more severe droughts and floods, and sea level rise. All these stresses can add to existing stresses on resources such as land-use changes and pollution. EPA determined, based on a full review of the scientific evidence and focusing on impacts within the United States, that six greenhouse gases (including CO_2 and methane) endanger both the public health and the public welfare.[130] In making this finding, EPA pointed to risks to human health associated with changes in air quality, increases in temperatures, changes in extreme weather events, increases in food- and water-borne pathogens, and changes in aeroallergens. The agency concluded that "[t]he evidence concerning adverse air quality impacts provides strong and clear support for an endangerment finding."[131]

The impacts of global warming on West Virginia are tangible and worrisome:

- West Virginia's agriculture industry experienced losses of more than $80 million in 1999, the driest growing season on record in the eastern United States. Continued warmer, drier conditions projected with global warming could increase such droughts.

---

[127] *See* Ken Ward, Jr., Mingo Liquid Coal Plant: What about the carbon dioxide? http://blogs.wvgazette.com/coaltattoo/2009/10/28/mingo-liquid-coal-plant-what-about-the-carbon-dioxide/.

[128] Engineering Evaluation at 6.

[129] *See* http://www.ipcc.ch/ipccreports/assessments-reports.htm; EPA, Ground-Level Ozone: Health and Environment, March 6, 2007, http://www.epa.gov/air/ozonepollution/health.html; EPA, Particulate Matter: Health and Environment, January 17, 2008, http://www.epa.gov/air/particlepollution/health.html; Jonathan A. Patz, et al., Impact of Regional Climate Change on Human Health, Nature, 438, 310-317, November 17, 2005, http://www.nature.com/nature/journal/v438/n7066/full/nature04188.html; EPA, Climate Change, Health and Environmental Effects, December 20, 2007, http://www.epa.gov/climatechange/effects/health.html; *See also*, Centers for Disease Control, CDC Policy on Climate Change and Public Health, available at http://www.cdc.gov/climatechange/pubs/Climate_Change_Policy.pdf.

[130] U.S. Environmental Protection Agency, Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, December 7, 2009, Docket ID No. EPA-HQ-OAR-2009-0171; http://www.epa.gov/climatechange/endangerment/downloads/FinalFindings.pdf.

[131] *Id.* at 10.

- Duck hunters already are seeing a direct relationship between warmer winters and decreased duck numbers. Not only are waterfowl not migrating as far south, but global warming is likely to decrease habitat in important breeding grounds such as the Prairie Pothole Region in the northern U.S.
- Global warming could increase the lifespan of disease-carrying insects such as mosquitoes and ticks, causing more cases of Lyme disease and West Nile virus.
- Loss of wildlife and habitat could mean a loss of tourism dollars. In 2006, more than 1.4 million people spent nearly $1.2 billion on hunting, fishing and wildlife viewing in West Virginia.[132]

Congress is actively considering regulating carbon emissions, with several bills offered this year. Based on this legislation, President Obama recently made a commitment to reduce greenhouse gas emissions in the range of 17 percent below 2005 levels by 2020 and 83 percent by 2050.[133] Many states, such as Montana, Washington, Delaware, California and New Jersey have also taken the initiative to limit greenhouse gases from industrial polluters.[134] As the Director of the Kansas Department of Health and the Environment recently stated in denying a permit application for the proposed 1,400 MW Holcomb coal plant, "it would be irresponsible to ignore emerging information about the contribution of carbon dioxide and other greenhouse gases to climate change and the potential harm to our environment and health."[135]

The 3.6 million tons/year of carbon dioxide that would be emitted by TransGas far exceed the EPA's proposed major source threshold for greenhouse gases of 25,000 tons/year.[136] The plant may also emit methane,[137] a greenhouse gas at least 21 times as

---

[132] *See* Exhibit 5, National Wildlife Federation, Global Warming and West Virginia, at http://www.nwf.org/globalwarming/pdfs/westvirginia.pdf.

[133] Obama to Go to Copenhagen With Emissions Target; http://www.nytimes.com/2009/11/26/us/politics/26climate.html?emc=eta1. Even if such legislation confers "grandfathered-in" status upon existing or already-approved coal plants, then emissions from the TransGas plant might constrain West Virginia's flexibility in that the state might have fewer carbon allowances to allocate to other carbon emitters.

[134] *See*, *e.g.*, Mt. Code 69-8-421(7); Del. Admin. Code 7 1000 1144 §§ 3.2.1.1, 3.2.2.1; Wash. Rev. Code 80.80; Cal. Pub. Util. Code § 8341.

[135] Kansas Dept. of Health and the Environment, Press Release: KDHE Electric Denies Sunflower Electric Air Quality Permit, October 18, 2007, available at http://www.kdheks.gov/news/web_archives/2007/10182007a.htm.

[136] EPA's proposed rule would "phase in the applicability thresholds for both the PSD and title V programs for sources of GHG emissions. The first phase, which would last 6 years, would establish a temporary level for the PSD and title V applicability thresholds at 25,000 tons per year (tpy), on a "carbon dioxide equivalent" (CO_2e) basis, and a temporary PSD significance level for GHG emissions of between 10,000 and 25,000 tpy CO_2e." 74 Fed. Reg. at 55291.

[137] Without a P&ID diagram it is difficult to discern whether any methane would be emitted to the atmosphere from the plant's processes, but it is clear that methane will be present at the facility. *See*, *e.g.*, Application, electronic page 57. Methane is a regulated pollutant under the Clean Air Act. New Source Performance Standards. *See* 40 CFR 61, Subparts Cc and WWW; *see* Exhibit 7. U.S. Environmental Protection Agency, Air Emissions from Municipal Solid Waste Landfills –

potent as carbon dioxide.[138] The Department must disclose any calculations of the plant's potential GHG emissions and limit those emissions to what is achievable with the best available control technology. Such a limit is required by the Clean Air Act, as explained below. The public should have an opportunity to review and comment upon Department's analysis.

In an effort to sell the TransGas facility as "clean," TransGas has trumpeted its purported intent to capture CO_2 emissions from the facility and transport them to Texas for enhanced oil recovery ("EOR") operations. However, the Application and Draft Permit reveal these statements to be empty promises. There is no analysis whatsoever as to whether such a proposition is technically feasible, how much carbon dioxide would be captured, and whether using it for EOR would actually result in permanent sequestration. The Draft Permit is also devoid of any requirement that TransGas take steps towards achieving carbon capture and sequestration ("CCS"). The West Virginia Legislature in 2009 adopted HB 2860 relating to carbon capture and sequestration and in 22-11A-1 (9) stated that:

"9) Carbon dioxide capture and sequestration is the capture and secure storage of carbon dioxide that would otherwise be emitted to, or remain in, the atmosphere. This technology is currently being used and tested to reduce the carbon footprint of electricity generated by the combustion of coal;"

While Sierra Club does not endorse CCS as a solution to climate change, the legislative finding that the technology is currently being used suggests that the Department should at a minimum consider it as a means of mitigating the plant's global warming emissions. As explained below, the Clean Air Act obligates such an analysis.

A. The Department Has a Duty Under State Law to Ensure that TransGas Limits its Emissions of Greenhouse Gases.

The Department has a duty as public trustee and agency in charge of air regulations to limit the greenhouse gases that would be emitted from the TransGas facility. *See* W.V. Code § 22-1-1 ("[O]ur government has a duty to provide and maintain a healthful environment for our citizens"). Furthermore, the Department is prohibited from granting this permit without mitigating the global warming impacts because it would allow the project proponent to emit carbon dioxide and other greenhouse gases such as methane in such quantities that would cause "statutory air pollution." The West Virginia Code provides: "It is unlawful for any person to cause a statutory air pollution ... without a valid permit." "Statutory air pollution" means "the discharge into the air by the act of man of substances (liquid, solid, gaseous, organic or inorganic) in a locality, manner and amount as to be injurious to human health or welfare, animal or plant life, or property, or which would interfere with the enjoyment of life or property."

Background Information for Proposed Standards and Guidelines at 2-15, EPA-450/3-90-011a, March 1991.

[138] *See* U.S. Environmental Protection Agency, Global Mitigation of Non-CO_2 Greenhouse Gases, 430-R-06-005, at I-2; http://www.epa.gov/climatechange/economics/downloads/GM_SectionI_TechnicalSummary.pdf.

Greenhouse gases plainly fit within this definition of air pollution because, as discussed above, adding more global warming pollution will accelerate global warming, causing further harm to human health, welfare, and animal and plant life. The Department may not allow TransGas to emit pollution, not covered by its air permit, that will cause such injury.

B. The Clean Air Act Requires a Best Available Control Technology Analysis for Greenhouse Gas Emissions from the TransGas Facility

As discussed above, TransGas must obtain a PSD permit, rather than a minor source permit, before constructing the proposed plant. A PSD permit for a source that emits significant quantities of a pollutant "subject to regulation" under the Clean Air Act must include an emissions limit based on the best available control technology ("BACT") for that pollutant.[139] There is no dispute CO_2 will be emitted from the TransGas plant. It also appears likely that the plant will emit methane. As discussed below, both CO_2 and methane are regulated under the Act. Therefore, the Department must require a BACT limit for these emissions.[140]

1. Carbon Dioxide and Methane Are "Pollutants" Under the Clean Air Act

There is no dispute that carbon dioxide satisfies the definition of "air pollutant" under the Clean Air Act. The Clean Air Act defines "air pollutant" expansively to include "any physical, chemical, biological, radioactive . . . substance or matter which is emitted into or otherwise enters into the ambient air."[141] The U.S. Supreme Court confirmed in *Massachusetts v. EPA*, 549 U.S. 497 (2007), that greenhouse gases fit within this expansive definition. The Court held that it is "unambiguous" that the "sweeping definition" of air pollutant found in the Act "embraces all airborne compounds of whatever stripe," including CO_2 and other greenhouse gases."[142]

2. Carbon Dioxide and Methane Are Currently Regulated Under the Clean Air Act

Carbon dioxide and methane are regulated in numerous ways, both by regulations that require the monitoring and reporting of CO_2 emissions and by regulations that limit the actual emissions of CO_2 and methane.[143]

---

[139] 42 U.S.C. § 7475(a)(4); see also 40 CFR § 52.21(b)(50) (2007).

[140] 42 U.S.C. § 7475(a)(3); 40 CFR § 52.21(j)(2); see also e.g., In re Northern Michigan University Ripley Heating Plant, PSD Appeal No. 08-02, Slip Op. at 31-32 (EAB February 18, 2009) (remanding permit for consideration of whether BACT for CO_2 and N_2O is required).

[141] 42 U.S.C. § 7602(g).

[142] *Id.* at 528-29. *See* In Re Deseret Power Electric Coop., PSD Appeal No. 07-03, Slip Op. (EAB November 13, 2008).

[143] Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule and Guidance, 61 Fed. Reg. 9905 (Mar. 12, 1996).

a) The Delaware SIP Includes "Actual Control" of CO_2 and Is Included in Subchapter C

CO_2 is subject to regulation under the Clean Air Act through EPA's approval of amendments adding various CO_2 regulations to the State Implementation Plan ("SIP") for the State of Delaware.[144] Therefore, Section 52.420(c) of Part 40 limits emissions of CO_2 in addition to establishing operating requirements, record keeping and reporting requirements, and CO_2 emissions certification, compliance, and enforcement obligations for new and existing stationary electric generators.[145] EPA's approval was made "in accordance with the Clean Air Act," 73 Fed. Reg. 23,101, and included the rule in Part 52.

The approved Delaware SIP limits emissions of CO_2 from certain electric generators to the following rates:[146]

	Delaware SIP Emission Limit
Existing Distributed Generators	1,900 lbs/MWh
New Distributed Generators	1,900 lbs/MWh (if installed between effective date and 1/1/2012) 1,650 lbs/MWh (if installed on or after 1/1/2012)
New Distributed Generators that use Waste, Landfill or Digester Gases	1,900 lbs/MWh

The regulated generators must certify compliance with these CO_2 emission limits, monitor, and keep records.[147]

The Delaware Regulation 1144 is "under the Act." Delaware submitted Regulation 1144, including the CO_2 emission limits contained therein, for EPA approval on November 1, 2007.[148] EPA determined that the submission satisfied the requirements under CAA § 110(a), and published notice of its approval of the SIP revision in the Federal Register on March 5, 2008.[149] EPA allowed for public comment and, on April 29, 2008, EPA published notice of its Final Rule approving the SIP revision, effective May 29, 2008, in the

---

[144] 73 Fed. Reg. 23,101 (April 29, 2008); 40 CFR § 52.420(c); *see also* Exhibit 6, Letter from Brian L. Doster, U.S. Environmental Protection Agency, US EPA Air and Radiation Law Office, to Eurika Durr, EAB, September 9, 2008: "... Office of General Counsel ... believe that it is incumbent on them, in recognition of a duty of candor, to inform the Board of a recent action by the Agency... EPA Region 3 issued a final approval of a Delaware SIP revision incorporating state regulations which include specific limitations on the rate of several pollutants, including carbon dioxide;"

[145] 40 CFR § 52.420(c) (adopting Del. Admin.Code 7 1000-1144 by reference).

[146] Delaware Department of Natural Resources and Environmental Control, Department of Air and Waste Management, Air Quality Management Section, Regulation No. 1144 § 3.2.1 – 3.2.2; http://regulations.delaware.gov/AdminCode/title7/1000/1100/1144.shtml#TopOfPage.

[147] Id. at §§ 4.0, 6.0, 7.0

[148] 73 Fed. Reg. 11845, 11846 (March 5, 2008).

[149] 73 Fed. Reg. 11845.

Federal Register.[150] Both the proposed and final rule notices state that EPA's approval of Delaware's Regulation 1144 was "under" and "in accordance with the Clean Air Act."[151]

b) CO_2 and Methane Are Also Both Subject to "Actual Control" as Two of the Landfill Gases Limited by the New Source Performance Standards Located in Subchapter C

EPA also promulgated emission standards for municipal solid waste ("MSW") landfill emissions in Subchapter C.[152] "MSW landfill emissions" are defined as "gas generated by the decomposition of organic waste deposited in an MSW landfill or derived from the evolution of organic compounds in the waste."[153] EPA has specifically identified CO_2 and methane as the two primary components of the regulated "MSW landfill emissions."[154] Thus, these pollutants are regulated through the landfill emission regulations at 40 CFR Part 60 Subparts Cc, WWW.[155]

EPA explicitly intended to control greenhouse gases, including methane and carbon dioxide, through the NSPS for landfills. In a background technical document for the NSPS standard, EPA acknowledged that air emissions of greenhouse gases, including carbon dioxide and methane "contribut[ed] to the phenomenon of global warming," and that the "global warming effects" of those emissions posed "potential adverse health and welfare effects."[156] In fact, any limit on landfill emissions necessarily limits carbon dioxide and methane because those two pollutants constitute nearly 100% of landfill gases—with other non-methane organic compounds constituting less than 1%. Therefore, EPA explained that one of the specific justifications for regulating landfill gases, and particularly for the level of stringency, was to limit emissions of methane to avoid global warming impacts.[157] EPA further noted in the rule's preamble to the final rule that "[c]arbon dioxide is also an important greenhouse gas contributing to climate change," and quantified the benefits of the rule based on "equivalent reduction in CO_2." 56 Fed. Reg. at 24472 (stating that "1.1 to 2.0 billion trees would need to be planted . . . to achieve an equivalent reduction in CO_2 as

---

150 73 Fed. Reg. 23101 (April 29, 2008).

151 73 Fed. Reg. at 11845; 73 Fed. Reg. at 23101.

152 40 CFR §§ 60.33c, 60.752.

153 40 CFR § 60.751.

154 *See* Exhibit 7, U.S. Environmental Protection Agency, Air Emissions from Municipal Solid Waste Landfills, explaining that "MSW landfill emissions, or [landfill gas], is composed of methane, CO_2, and NMOC."

155 *See* also 56 Fed. Reg. 24468 (May 30, 1991): "Today's notice designates air emissions from MSW landfills, hereafter referred to as 'MSW landfill emissions,' as the air pollutant to be controlled."

156 *See* Exhibit 7, U.S. Environmental Protection Agency, Air Emissions from Municipal Solid Waste Landfills, at 2-15.

157 *See* 56 Fed. Reg. 24468, 24481 (May 30, 1991) ("[i]n considering which alternative to propose as BDT, EPA decided to consider both NMOC's and methane reductions"); 61 Fed. Reg. 9905, 9906 (Mar. 12, 1996) ("Briefly, specific health and welfare effects from [landfill gas] emissions are as follows ... methane emissions ... contribute to global climate change as a major greenhouse gas"); *id.* at 9914 (anticipated "methane reductions ... are also an important part of the total carbon reductions identified under the Administration's 1993 Climate Change Action Plan").

achieved by today's proposal"). A rule limiting landfill gas emissions—consisting of 50% carbon dioxide and 50% methane—is clearly a rule limiting emissions of those two pollutants.

c) CO_2 Is Also Regulated under the Clean Air Act Through the Special Regulation of Auto Emission by Numerous States Pursuant to the Act's California Car Waiver

EPA authorized the state of California to implement its motor vehicle greenhouse gas emission standards, pursuant to Section 209(b) of the Clean Air Act, 42 U.S.C. § 7609(b), on June 30, 2009.[158] As a result, CO_2 was immediately subject to emission limits not only in California, but also in 10 of the 14 other states that have imposed these same standards pursuant to their independent authority under Section 177 of the Clean Air Act, 42 U.S.C. § 7507. As a result, carbon dioxide and methane now "subject to regulation" under the "California Car Waiver" provisions of the Clean Air Act.

The EPA's approval of new motor vehicle standards unequivocally requires "actual control" of CO_2 and methane emissions:

> California's greenhouse gas emissions standards establish allowable grams per mile (gpm) levels for greenhouse gas emissions, including tailpipe emissions of carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4), as well as emissions of CO_2 and hydrofluorocarbons (HFCs) related to operation of the air conditioning system.[159]

California's grams-per-mile standards (the "CO_2 Emission Limits") are effective for model years 2009 through 2016:

> [California's] regulation covers large-volume motor vehicle manufacturers beginning in the 2009 model year, and intermediate and small manufacturers beginning in the 2016 model year and controls greenhouse gas emissions from two categories of new motor vehicles -- passenger cars and the lightest trucks (PC and LDT1) and heavier light-duty trucks and medium-duty passenger vehicles (LDT2 and MDPV).[160]

Because Model Year 2010 began on January 2, 2009 (and Model Year 2009 began on January 2, 2008[161]), the "CO_2 Emission Limits" are currently in effect and govern CO_2 and methane emissions from all new motor vehicle sales and registrations. Moreover, these limits are in effect in 10 states beyond California: Connecticut, Maine, Massachusetts, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Vermont, and Washington.[162]

---

[158] 74 Fed. Reg. 32744 (July 8, 2009).

[159] 74 Fed. Reg. 32752.

[160] *Id.* at 32746.

[161] *See* 40 CFR 85.2304.

[162] Cal. Code RTEC. tit. 13, § 1961.1(a); Conn. Agencies RTEC. § 22a-174-36b(b)(3); 06-096-127 Me. Code R. § 1(B)(4); 310 Mass. Code RTEC. 7.40(2)(a)(6); N.J. Admin. Code § 7:27-29.13; N.Y. Comp.

Each of these states adopted the CO_2 and methane limits pursuant to Section 177 of the Clean Air Act, 42 U.S.C. § 7507. Section 177 expressly grants other states the authority to adopt California's vehicle emission standards:

> Section 177 of the Act contains an "opt-in" provision that allows any other state to "adopt and enforce for any model year standards relating to control of emissions from new motor vehicles" if "such standards are identical to the California standards for which a waiver has been granted for such model year" and are adopted "at least two years before commencement of such model year."[163]

American Automobile Manufacturers Association v. Cahill, 152 F.3d 196, 198 (2d Cir. 1998). But for this provision of the Clean Air Act, states would not have been allowed to limit tailpipe emissions of CO_2 and methane. In short, the auto emission standards are regulations under the Clean Air Act. In fact, two federal courts have found that these very CO_2 Emission Limits are indeed federal Clean Air Act standards. In *Central Valley Chrysler-Jeep, Inc. v. Goldstene*, 529. F.Supp.2d 1151, 1165 (E.D. Cal. 2007), the court rejected the notion that even when approved under Section 209 of the Act, the CO_2 Emission Limits are and remain state regulations and therefore subject to preemption by the federal Energy Policy and Conservation Act ("EPCA"): "The court can discern no legal basis for the proposition that an EPA-promulgated regulation or standard functions any differently than a California-promulgated and EPA-approved standard or regulation."[164] Faced with the identical argument, the court in *Green Mountain Chrysler v. Crombie*, 508 F.Supp.2d 295, 350 (D.Vt. 2007), also rejected the idea that the CO_2 emission limits were not federal standards, concluding "that the preemption doctrine does not apply to the interplay between Section 209(b) of the CAA and EPCA, in essence a claim of conflict between two federal regulatory schemes."

Moreover, states have been exercising their Section 177 authority for almost two decades; the first to do so was New York, adopting California's original Low Emission Vehicle standards in 1992.[165] Not only have states adopted these emission standards under their Section 177 authority, but typically each state will then incorporate the more stringent auto emission standards into its SIP under Section 110 of the Act, 42 U.S.C. § 7410.[166] Once incorporated into a SIP, these requirements become CAA standards, and

---

Codes R. & RTEC tit. 6, § 218-8.2; Or. Admin. R 340-257-0050(2)(e); 25 Pa. Code 124.412; see also 36 Pa. Bull. 7424; 12-031 R.I. Code R. § 37.2.3; 12-031-001 Vt. Code R. § 5-1106(a)(5); Wash. Admin. Code 173-423-090(2). In three more states and the District of Columbia, these standards will come into effect in subsequent model years. Ariz. Admin.Code § R18-2-1801; Md. Code RTEC. 26.11.34.03; N.M. Code R. § 20.2.88.101; D.C. Law 17-0151.

163 42 U.S.C. § 7507.

164 *Id.* at 1173.

165 *Motor Vehicle Manufacturers Association v. New York State Department of Environmental Conservation*, 17 F.3d 521, 529 (2d. Cir. 1994).

166 *See*, *e.g.*, 40 CFR § 52.370(c)(79) (EPA approval of §177-adopted standards as part of Connecticut's SIP); 40 CFR § 52.1020(c)(58) (Maine); 40 CFR § 52.1120(c)(132) (Massachusetts); 40 CFR §52.1570(c)(84)(i)(A) (New Jersey); 40 CFR § 52.2063(c)(141)(i)(C) (Pennsylvania).

numerous provisions authorize both EPA and citizens to enforce such SIP requirements.[167,168]

d) CO_2 Is Regulated Through Monitoring and Reporting Requirements

In section 821 of the 1990 Amendments to the Act, Congress made CO2 "subject to regulation" for purposes of the Act's Section 165 BACT provisions. Enforcement of Section 821 is accomplished through the enforcement mechanism in the Act, 42 U.S.C. §§ 7413(a)(4), (b)(2),7604(a)(1), and a violator is subject to the penalty provisions of the Act.[169] In 1993, EPA issued the regulations required by Section 821. 40 CFR Part 75. Those regulations generally require monitoring of carbon dioxide emissions through installation, certification, operation, and maintenance of a continuous emission monitoring system or an alternative method, 40 CFR §§ 75.1(b), 75.10(a)(3); preparation and maintenance of a monitoring plan, 40 CFR § 75.33; maintenance of certain records, 40 CFR § 75.57; and reporting of certain information to EPA, including electronic quarterly reports of carbon dioxide emissions data, 40 CFR §§ 75.60 - 64.

Additionally, 40 CFR § 75.5 prohibits operation of an affected source in the absence of compliance with the substantive requirements of Part 75, and provides that a violation of any requirement of Part 75 is a violation of the Clean Air Act. These regulations are located in Title 40, Chapter I, Subchapter C, which makes them "regulation[s] under the Act," according to EPA's only official interpretation.[170]

Furthermore, EPA has identified the CO_2 monitoring and reporting requirements in Part 75 as applicable Clean Air Act requirements that must be incorporated into Title V operating permits. 40 CFR § 71. EPA has enforced CO_2 monitoring regulations under the Clean Air Act on a number of occasions. It is, therefore, undeniable that CO_2 is subject to regulation under the Clean Air Act.

For these reasons, the Department must quantify and limit the TransGas plant's emissions of CO_2 and methane and release a new draft permit for public review.

---

[167] *See*, *e.g.*, 42 U.S.C. § 7413; 42 U.S.C. § 7604(a)(1), (f)(3).

[168] Because the CO_2 Emission Limits also provide significant criteria pollutant benefits (74 FR 32758) California has already included these emissions reductions into its 2007 ozone and PM SIP submittals to EPA. http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm.

[169] 42 U.S.C. § 7651k(e).

[170] *See* 43 Fed. Reg. 26,388, 26,397 (June 19, 1978); In Re: Deseret Power Electric Cooperative , PSD Appeal No. 07-03, Slip Op. at 41 (Nov. 13, 2008), http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/PSD+Permit+Appeals+(CAA)/C8C5985967D8096E85257500006811A7/$File/Remand...39.pdf (holding that the fact that CO_2 is regulated by rules contained in 40 CFR Subchapter C "augers in favor" of a conclusion that CO_2 is "subject to regulation under the Act," based on EPA's official interpretation in its 1978 rulemaking).

XI. The Draft Permit Fails to Address Odorous Emissions

Under West Virginia law, "[n]o person shall cause . . . the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public."[171] Although the Draft Permit reiterates this requirement, and TransGas admits that it is subject to this regulation[172], the Department has not directly limited emissions of hydrogen sulfide or ammonia, which can both cause odor problems. For example, the application to build the Hyperion Refinery in South Dakota, which includes a coal gasification and Rectisol component much like TransGas, depicts the CO_2 vent from the Rectisol system as being a source of 4.2 tons per hour and 18 tons/year of hydrogen sulfide emissions.[173] Despite the remote location of the proposed plant, the Department must evaluate whether similar emissions of hydrogen sulfide (H2S) or other odorous emissions from the TransGas plant will "contribute to an objectionable odor at any location occupied by the public," such as public roads. If so, state law requires that these emissions be reduced. The permit limits sulfur gas emissions to 1 ppm, which will be mostly H2S and COS. The odor detection limit for H2S in humans is 0.0047 ppm.

XII. The Draft Permit Fails to Assure Compliance with All Applicable Regulations

As discussed above, the Draft Permit fails to comply with the requirements of the Clean Air Act's Prevention of Significant Deterioration program. Apart from this major flaw, there are a number of other regulations that TransGas has evaded without sufficient justification.

A. Performance Standards for VOC Emissions from SOCMI Distillation Operations

The Department's determination that 40 CFR 60 Subpart NNN: Standards of Performance for Volatile Organic Compound Emissions from the Synthetic Organic Chemical Manufacturing Industry ("SOCMI") Distillation Operations is not applicable is incorrect. The Engineering Evaluation indicates that the only distillation at the TransGas facility occurs in the MTG process, which utilizes methanol as a raw material.[174] However, the Department did not consider that ethylene, propylene, and mixed butenes are also listed chemicals under 40 CFR § 60.667. As shown in Technical Appendix Section IV, these chemicals are produced as byproducts in the MTG process at quantities above the applicability threshold in 40 CFR 60.660(c)(5).

The Department's point that "the distillation units do not vent to atmosphere", does not excuse TransGas from NNN applicability because 40 CFR 60.660(a)(2)and (3) provide for distillation systems that include "recovery system." Therefore, TransGas is subject to

[171] 45 CSR § 4-3.1.

[172] Application, Attachment D at p. D1.

[173] Hyperion Energy Center, PSD Permit Application, December 2007 at 100-01, available at http://denr.sd.gov/Hyperion/Air/20071220HyperionApplication.pdf.

[174]Engineering Evaluation at 27.

the provisions of 40 CFR 60, Subpart NNN for olefin byproducts from the MTG process. The Department must revise the Draft Permit to incorporate these provisions.

B. Performance Standards for Coal Preparation and Processing Facilities

The Draft Permit does not fully comply with the new federal performance standards for coal preparation and processing facilities, 40 CFR 60, Subpart Y, which became effective on October 8, 2009.[175] Those standards apply to all the coal-handling equipment at the TransGas plant, including "coal processing and conveying equipment (including breakers and crushers), coal storage systems, and transfer and loading systems" that is mechanically vented to the atmosphere.[176] This equipment must meet a PM emissions limit of 0.023 g/dscm and maintain opacity levels of less than 10 percent. The rule also contains requirements for open storage piles, including the equipment used in the loading, unloading and conveying operations. For those sources, the owner or operator must prepare and operate in accordance with a fugitive coal dust emissions control plan which identifies the control measures the owner/operator will use to minimize fugitive coal dust emissions. The new federal rule dovetails with the state's existing requirement that the operator "minimize" emissions of fugitive particulate matter.[177] Under state law, to "minimize" means that a "system shall be installed, maintained and operate to ensure the lowest fugitive particulate matter emissions reasonably achievable."[178]

While it is encouraging that the Draft Permit requires most elements of the coal handling system to be either partially or fully enclosed, it does not appear that TransGas has submitted a "fugitive dust control plan" in accordance with the federal rule. In submitting a plan, TransGas must determine whether the proposed measures "minimize" dust emissions, or whether any of the additional measures listed in the rule (*e.g.*, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents, use of a wind barrier, compaction) could serve to further reduce dust emissions. If any of these measures could reasonably achieve lower fugitive PM emissions, they must be included in the permit pursuant to 45 CSR §7.5.1.

Additionally, although Permit Condition 4.1.4.7 states that exhaust and off gases from the coal and limestone feed bunkers shall be controlled by particulate matter filters as specified in Table 1.0, Table 1.0 does not include such a specification. The control devices listed for the bunkers areVF1-VF10, but "VF" is never defined as a particulate matter filter.

Finally, the Draft Permit creates confusion in that it references the opacity limits of the new Subpart Y in Condition 4.1.4.14 for enclosed coal processing and conveying equipment (10%), but allows a more lenient standard of 20% in Condition 4.1.4.11. Likewise, the Department appears to have erroneously exempted the coal dust feeding system from the requirements of Subpart Y. Although the coal dust feeding system

---

[175] Standards of Performance for Coal Preparation and Processing Plants: Final Rule, 74 Fed. Reg. 51950 (October 8, 2009).

[176] *Id.* at 51592.

[177] 45 CSR § 7.5.1.

[178] *Id.*

includes coal-handling equipment that will mechanically vent to the atmosphere, and is thus subject to Subpart Y's 10% opacity limit, Condition 4.1.5.2 allows emissions of smoke and/or particulate matter from the coal dust feeding system to be as high as 40%. Also confusing, Condition 4.1.5.2.c references Condition 4.1.8.7.b, which does not exist. The Department must revise the permit to be both internally consistent and consistent with the performance standards in 40 CFR 60, Subpart Y.

C. National Emission Standards for Hazardous Air Pollutants

Although the Department states on page 31 of the Engineering Evaluation that it analyzed the applicability of 40 CFR 61, which sets forth standards for certain HAPs from certain sources, the Engineering Evaluation does not include such an analysis. The Department should evaluate National Emission Standards for Hazardous Air Pollutants ("NESHAPs") applicable to emissions of benzene, and other HAPs produced at the TransGas facility for which NESHAPs exist.[179]

At a minimum, the facility is subject to Subpart J, the standard addressing equipment leaks of benzene, and Subpart V, which includes Leak Detection and Repair requirements applicable to equipment subject to Subpart J. Equipment at a plant that is expected to produce at least 1,102 tons of benzene per year either contains or contacts a fluid that is at least 10 percent benzene by weight is subject to Subpart J. As shown in the Technical Appendix Section V, equipment associated with the MTG Process meets these criteria.

D. Standards of Performance for Petroleum Refineries

As shown below, a number of components of the TransGas plant are subject to the provisions of 40 CFR 60 Subpart Ja, "Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007" (hereinafter "Subpart Ja"). Yet, the Draft Permit and Engineering Evaluation fail to address the relevant provisions.

Subpart Ja applies to fuel combustion devices, such as flares, and sulfur recovery plants at petroleum refineries. For purposes of Subpart Ja, "petroleum," means "the crude oil removed from the earth and the oils derived from tar sands, shale, and coal."[180] Since TransGas produces crude gasoline, final gasoline, and LPG from coal and coal derivatives, the gasoline and LPG produced at TransGas will meet the definition of "petroleum" under 40 CFR § 60.101a. A "petroleum refinery" means "any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives."[181] While EPA did not make clear what it meant by "oil" "derived from ... coal" for purposes of this Subpart, the crude gasoline derived

---

[179] *See*, *e.g.*, 40 CFR 61 Subpart FF, National Emissions Standards for Benzene Waste Operations; 40 CFR 61 Subpart V, National Emission Standard for Equipment Leaks.

[180] 40 CFR § 60.101a

[181] *Id.*

from coal and distilled in the MTG process appears to fall into that category.[182] Thus, since the TransGas MTG process produces gasoline through the distillation of petroleum, it meets the definition of "petroleum refinery."

As a "petroleum refinery," the TransGas plant's sulfur recovery plant and fuel combustion units are subject to the requirements of Subpart Ja, including, for example, the requirement to develop a flare management plan.

Under Subpart Ja, "sulfur recovery plant" means all process units which recover sulfur from H_2S and/or SO_2 at a petroleum refinery. As described in the Engineering Evaluation (p. 6), the Sulfur Recovery Unit at the TransGas plant would convert "sulfur containing compounds into elemental sulfur." The Application also indicates that the SRU processes H_2S, and repeatedly refers to a Claus sulfur recovery process – a type of process that EPA has explicitly determined is subject to Subpart Ja.[183] Thus, TransGas must comply with the performance standards for sulfur recovery plants set forth in Subpart Ja.

The Applicant has also indicated its intent to combust, in the startup boiler[184], "fuel gas" generated in the MTG process; to combust "fuel gas" and "MTG tail gas" in the MTG heater[185]; and to combust MTG tail gas in the flare[186]. As such, the fuel gas and MTG tail gas meets the definition of "fuel gas" in 40 CFR 60.101a, and the boiler, the heater, and the flare each meets the definition of "fuel gas combustion device."[187]

---

[182] For example, the American Heritage Dictionary defines "oil" as "[a]ny of numerous mineral, vegetable, and synthetic substances and animal and vegetable fats that are generally slippery, combustible, viscous, liquid or liquefiable at room temperatures, soluble in various organic solvents such as ether but not in water, and used in a great variety of products, especially lubricants and fuels."

[183] EPA has indicated that Subpart Ja applies to Claus sulfur recovery units at coal-to-liquids plants, such as that proposed by TransGas. *See* Exhibit 8, U.S. Environmental Protection Agency memorandum entitled "Applicability Determination for Solvent Refined Coal Plants" Control No. J015 by Edward E. Reich, March 19, 1980. Attachment L for Equipment ID "Sulfur Recovery" of Appendix M in the Application makes reference to "Claus Furnace," "Claus Reactor I," and "Claus Reactor II;" Application, Attachment N, Attachment 1 "Response on DEP Questions" at 23 and 24 makes numerous references to a "Claus Furnace," "Claus Reactor I," and "Claus Reactor II."

[184] Application, Attachment N, Attachment 1 "Response on DEP Questions," Section 3.13 at 25 makes reference to "fuel gas" flow rates and "periods of fuel gas" for consideration in emissions from combustion in the "F Start-up Steam Boiler"

[185] Application, Attachment N, Attachment 1 "Response on DEP Questions," Section 3.10 at 22 indicates that the MTG Heater (referred to as "E3 MTG HGT") will be fired "4 times a year, each 10 hours" on fuel gas. Section 3.12 of the same document indicates that "part of the tail gas could also be utilized as fuel gas in fired heaters of the MTG process."

[186] Application, Attachment N, Attachment 1 "Response on DEP Questions," Section 3.12, at 24 indicates that TransGas proposes "flaring of MTG tail gas, when MTG plant is in operation ... and entire front end of plant is down."

[187] 40 CFR 60.101a (defining "fuel gas" as "any gas which is generated at a petroleum refinery and which is combusted", and defining "fuel gas combustion device" as "any equipment, such as process

The Claus sulfur recovery process including sulfur pits, the startup boiler, the E3 MTG HGT heater, the catalytic cracking unit, and the flare are subject to the emission limitations, the work practice standards, testing requirements, the monitoring requirements, and the recordkeeping and reporting requirements of 40 CFR 60 Subpart Ja. The Department must revise the Draft Permit to incorporate these provisions.

XIII. The Draft Permit's Monitoring Requirements Are Inadequate

State law requires that the Department impose "enforcement conditions which assure that all emission limitations contained within the permit are quantifiable, permanent and practicably enforceable."[188] Thus, each emission limitation in the Draft Permit and Appendix A must be accompanied by monitoring, recordkeeping, and reporting provisions that will provide the Department with sufficient data to determine whether TransGas is in compliance with the limitations. Additionally, to enforce the plant's purported "minor source" status, each assumption and limit that TransGas relies upon to remain below the major source thresholds for criteria pollutants and HAPS must be accompanied by appropriate monitoring. According to EPA, production and operation limits used to limit potential to emit should be expressed and monitored over the shortest time period possible.

> For these limitations to be enforceable as a practical matter, the time over which they extend should be as short term as possible and should generally not exceed one month. . . . The requirement for a monthly limit prevents the enforcing agency from having to wait for long periods of time to establish a continuing violation before initiating an enforcement action . . . Under no circumstances would a production or operation limit expressed on a calendar year annual basis be considered capable of legally restricting potential to emit.[189,190]

As specified below, the Draft Permit contains inadequate monitoring provisions to allow determinations of continuous compliance with the applicable permit emissions limitations and requirements, rendering those limitations unenforceable as a practical matter.

A. Monitoring of CO, PM, and PM10 Emissions from the Cooling Tower

The monitoring requirements for CO, PM, and PM10 emissions from the cooling tower are not enforceable as a practical matter.

---

heaters, boilers, and flares, used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.")

[188] 45 CSR §13.5.11.

[189] Exhibit 2 at 9-10.

[190] *See* also Sierra Club v. EPA, 536 F.3d 673, 675 (D.C. Cir. 2008) (noting that annual testing does not ensure compliance with a daily emission limit).

1. CO Emissions

We previously commented that the cooling tower emit a substantial amount of CO due to leakage of process fluids into the cooling water. In response, DEP has added a condition that states: "Water circulated in the Cooling Tower shall contain no reasonably detectable amount of CO."[191] Compliance with this condition is determined by "periodically" monitoring the cooling water for "reasonably detectable levels of CO."[192] No recordkeeping or reporting is required. These conditions are not practically enforceable and thus do not assure that emissions of CO remain below the major source threshold.

The phrases "reasonably detectable" and "periodically" are ambiguous, allowing the permittee wide latitude in determining how frequently to monitor and how accurately to measure. A test method is not specified. The term "periodically" would allow the permittee to monitor as infrequently as once over the life of the facility. What would a "reasonable" CO detection limit be? A "reasonably detectable amount of CO" at the cooling tower could still result in substantial CO emissions from the cooling tower. These conditions thus do not satisfy the burden to assure CO emissions remain below the major source threshold.

The CO emissions should be monitored continuously as the CO originates from leaks in heat exchangers which occur at unpredictable intervals. Infrequent monitoring could allow undetected leaks to exceed the major source threshold before they are detected. The CO measurements should be used together with circulating water flow rate, discussed below, to calculate CO emissions. These cooling tower emissions should be summed with other sources of CO and compared with the major source threshold. Further, the Draft Permit does not require that a detection of CO lead to leak location and repair in a time certain or even any reporting that would alert DEP and concerned citizens. Thus, the Draft Permit should be revised to specify the test method and provide a monitoring protocol.

2. PM and PM10 Emissions

The Application estimated PM and PM10 emissions using the procedure set out in AP-42, Section 13.4. This procedure involves multiplying the circulating water flow rate times the total dissolved solids ("TDS") concentration in the circulating water times the drift fraction. The Draft Permit sets limits on these three variables, restricting the circulating water flow rate to 308,167 gpm, the total dissolved solids to 5,000 ppm, and the mist eliminator maximum drift rate to 0.001%.[193]

To assure that PM/PM10 emissions remain at or below the levels calculated in the Application, all three of these variables must be measured. The Draft Permit requires that TDS be measured weekly with the option of reducing the testing frequency to monthly.[194] However, the Draft Permit does not require that either the circulating water flow rate or

---

[191] Draft Permit, Condition 4.1.7.2(b).

[192] Draft Permit, Condition 4.2.7.3(b).

[193] Draft Permit, Condition 4.1.7.2(a).

[194] Draft Permit, Condition 4.2.7.3(b).

the drift rate be tested. Thus, [195] the cooling tower limits set on these parameters are not enforceable. Weekly to monthly testing of TDS in the circulating water is not adequate to assure that PM/PM10 emissions remain below the major source threshold as excursions would be based on unpredictable leaks, as discussed above.

B. Monitoring of the Flare

There are several problems with the Draft Permit's monitoring program, or lack thereof, for the flare. First, although the Department has relied upon high destruction efficiencies of the flare in its estimate of potential emissions and specified annual and startup/shutdown limits of emissions from the flare in Appendix A to the Draft Permit, the Draft Permit does not contain a plan for monitoring most of these emissions. Since emissions from the type of flare proposed are not easily characterized directly, such as via source tests or stack tests, flare emissions monitoring generally relies on a combination of monitoring gas feed quantities and composition to the flare, as well as indirect monitoring of emissions impacts from flares such as remote monitoring. The Draft Permit requires TransGas to continuously monitor the H_2S concentration of all gas vented to the flare, and to monitor the CO content and total reduced sulfur (including H_2S) of raw syngas sent to the flare during gasifier startups and shutdowns. However, there is no monitoring plan in place to ensure that emissions of other pollutants from the flare meet the limits listed in Appendix A, rendering those limits unenforceable as a practical matter. Similarly, although the Draft Permit sets hourly limits on the volume of raw syngas sent to the flare from the gasifiers and AGR (Draft Permit Conditions 4.1.5.5(e) and 4.1.5.6(e)), there is no requirement that TransGas monitor these volumes on an hourly basis.

C. Monitoring of PM Emissions and Opacity

The required monitoring of PM and opacity limits from the facility's material handling operations are inadequate to ensure that emission limits in the permit are practically enforceable, as required by 45 CSR §13.5.11. Although the Draft Permit and Appendix A set forth detailed hourly and daily PM and PM_{10} limits for all components of the material handling system, the Draft Permit does not require that PM emissions from most of these components be monitored at all, let alone on a daily or hourly basis. In order to "demonstrate continuous compliance" with the "aggregate fugitive particulate matter emission limit in Appendix A,"[196] Condition 4.2.4.3 requires only that TransGas use "appropriate emission factors for each fugitive source that were used to estimate the source's potential emissions in the permit application." In other words, TransGas need only submit an estimate of emissions based on the same self-fulfilling assumptions it used in its application regarding fugitive dust emissions, without ever ground-truthing those assumptions. This does not nearly suffice to ensure that the facility maintains compliance with permit limitations and assumptions.

---

[195] Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, November 1995(available at http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf).

[196] It is unclear to which emission limit this language refers.

Condition 4.2.4.3 is the only specific requirement for particulate matter emissions "monitoring" in the permit. While Condition 4.2.4.4 incorporates the requirements in 40 CFR 60, Subpart Y, which set forth particulate matter monitoring standards for enclosed equipment (*i.e.*, that which "is mechanically vented" to the atmosphere), the many conveyers, coal transfer points, and dump bins at the facility which are only partially enclosed may not be subject to those standards. As such, the Draft Permit does not appear to require any monitoring whatsoever from these components, rendering many of the limits in Appendix A unenforceable.

Likewise, the monitoring required in Condition 4.2.4.2 "for the purpose of determining continuous compliance with the opacity limits" is inadequate and inconsistent with the monitoring requirements for coal processing plants in 40 CFR 60, Subpart Y. First, visible emissions checks are required only once a month. Such infrequent testing does not demonstrate "continuous" compliance. Moreover, inconsistencies between the permitted methods for opacity in Condition 4.2.4.2(c). and in Subpart Y render the permit ambiguous.[197] Subpart Y requires an initial performance test based on 40 CFR Part 60, Appendix A, Method 9, whereas the Draft Permit requires a Method 9 test only if visible emissions are identified for three months in a calendar year. The Department should resolve this ambiguity and ensure compliance with the opacity limits in the permit, and Subpart Y.[198]

D. VOC and HAP Emissions from Truck Loading Rack

The Applicant's emission estimates for VOC emissions from the loading racks rely on a vapor recovery system with a control efficiency of 99% and a MACT-level collection efficiency of 99.2% accounting for leakage from both the cargo tank and the collection system.[199] This MACT-level collection efficiency is only warranted if both the collection system and each and every cargo tank loading gasoline at the site passes an annual MACT-level leak test. While the Draft Permit contains a condition requiring the Applicant to comply with all requirements relating to the loading racks as given under 40 CFR 60, Subpart XX and 40 CFR 63, Subpart R, the Draft Permit fails to spell out the testing, reporting, and monitoring requirements to ensure that the Applicant complies with these requirements.

E. Monitoring of Other Emissions

Other than opacity and particulate matter, the Draft Permit does not appear to require monitoring of any actual emissions from the plant. While the Draft Permit does require monitoring of the constituents of some process streams, this monitoring does not necessarily substitute for an occasional test of what is actually released to the atmosphere to ensure that the assumptions made about the efficiency of control equipment and other

---

[197] *See* 74 Fed. Reg. at 51956.

[198] Exhibit 9, Letter from Bharat Mathur, U.S. Environmental Protection Agency, Region 5 to Robert F. Hodanbosi, Ohio Environmental Protection Agency, November 21, 2000, at 8 ("Ambiguous language hampers the source in its duty to independently assure compliance, and leaves legal requirements open to interpretation.").

[199] Application, Attachment N at N17.

factors comport with reality. This testing is also insufficient to make the many emissions limits for VOCs, CO, SO_2, NO_x and other pollutants contained in Appendix A practically enforceable.

While Permit Condition 3.3.1 appears to require stack testing, it merely refers to requirements applicable to all sources and does not specify the permittee's obligations, making enforcement difficult. The only source-specific requirement for a demonstration of "actual emissions" is found in Condition 4.2.1. That Condition in fact requires only an estimate of actual emissions, much like the estimates relied upon in the permit application, using "emissions factors, emission modeling software, or other appropriate emission estimation models." Although methodologies developed from site-specific testing or data is presented as an *option* for demonstrating actual emissions, the Draft Permit does not actually require that TransGas use site-specific testing or data. In short, the Draft Permit does not require the permittee to ground-truth its emissions estimates. This will leave the Department and the public in the dark as to the facility's public health and environmental impacts and make it impossible to know whether the facility is in compliance with its permit.

F. Other Enforceability Concerns

The permit condition limiting the sulfur content to 0.5%, and various other assumptions based on coal content, are not supported because TransGas has not identified from what coal seams it plans to obtain its coal. The applicant should be required to demonstrate, prior to construction, that it will be able to obtain enough of this ultra-low sulfur coal to fuel the plant for its expected life. Several air permits issued by the Department in the past have failed to specify an adequate coal supply, with the result that the plant cannot meet the original permit specifications, and must either find new fuel sources or exceed permit limits by burning lower quality fuels (e.g., Grant Town, Western Greenbrier). In the past, the Department has condoned higher emissions levels by allowing permit modifications. This is not an acceptable solution.

G. The Draft Permit Should Require Immediate Corrective Actions upon Discovery of Any Exceedance of an Emissions Limit or Operational Limitation

The Draft Permit fails to indicate what actions TransGas must take if it finds, through monitoring or other site-specific data, that the assumptions relied upon in its application were wrong, or that it has exceeded emission limits in Appendix A. If issued, the permit should be revised to require that the permittee take immediate steps to reduce emissions below permitted levels or, where applicable, to stay within the operational limitations relied upon in estimating potential emissions.

XIV. The Department Should Correct Drafting Errors in the Draft Permit and Make Vague Provisions More Specific

In addition to the vague, non-existent, or inconsistent permit conditions mentioned above in the context of the monitoring provisions and other comments, there are several additional places where the language in the permit should be tightened to ensure there is no ambiguity in what is required of the permittee and for ease of enforcement:

- The Draft Permit should be revised to include a table summarizing maximum annual criteria pollutant and HAP emissions from the facility. Because the documents provided by the Applicant contain numerous inconsistencies (*e.g.*, the summary table provided in Attachment N is inconsistent with the Attachments 1 through 3 to Task Order 1 authored by Uhde), the Department must take care to identify the correct emission rates for each emissions unit.

- The Draft Permit specifies the flare would, at a minimum, destroy CO at an 8-hour average rate of 99.5%[200] and total reduced sulfur ("TRS") compounds at a 3-hour average rate of 98%.[201] It appears that the condition specifying the minimum TRS destruction is in error and is likely the intended destruction efficiency of the flare for VOC as the Draft Permit fails to specify a VOC destruction rate for the flare. The Draft Permit should be revised accordingly.

- The Draft Permit fails to limit the number of startups per year and the number of hours per startup.

- Draft Permit Condition 4.1.7.3 lists the maximum number of turnovers and maximum throughput in gallons for each storage tank without indicating that these limits are annual limits.

- Draft Permit Section 1.0 fails to specify the use of a drift eliminator with a 0.001% control efficiency as required by Draft Condition No. 4.1.7.2(a). Section 1.0 should be revised accordingly in the final version of the permit.

- Appendix A to the Draft Permit sets emission limits on "Stockpiles" generally. Applying the limits to emission points OS1, OS2 and SSP specifically would provide more clarity. Similarly, it is unclear whether the emission limits on "Material Transfer Points" in Appendix A apply to all dump bins, conveyers, and belts.

- Attachment A to the Evaluation does not reflect that each pressure relief device is routed through a closed loop system back to the process as required in Draft Permit Condition No. 4.1.9.1. For purposes of public review, the diagram should have reflected the proposed design of the facility. It should be clarified that the process flow diagram included in Attachment A does not represent the permit's requirements, or the diagram should be redrawn.

- Some of the language in Draft Permit Condition 4.1.4.9 is overly vague. The permit should specify how often the permittee should use measures such as a vacuum sweeper truck (currently "as needed"), water/chemical sprays (currently "as often as is necessary"), and how promptly the permittee must collect material spilled on haul roads (currently "in a timely fashion"). Alternatively, the Department should implement an inspection protocol to ensure that the

[200] Engineering Evaluation at 11.

[201] Draft Permit, 4.1.8.2(b).

permittee is employing the measures frequently enough to minimize fugitive dust.

In addition, the Department has limited throughput of some materials but not others:

- Draft Permit Condition 4.1.7.4(b) restricts the total maximum throughput of gasoline at the truck and railcar loading racks to 275,940,000 gallons per year. However, the Draft Permit fails to restrict the total maximum throughput of LPG. (Application, Attachment L at L85 shows a maximum annual throughput for LPG of 210,240,000 gallons /year).

Finally, the Department has incorrectly defined the following:

- Emission calculations for discharges through the flare during startup are based on a flow rate of 100,000 cubic meters at normal conditions ("m^3n") per startup. Normal conditions are defined as 20 degrees centigrade and 1 atmosphere.[202] The Draft Permit incorrectly defines normal conditions as 0 degrees centigrade and 1 atmosphere.[203] Thus, the Draft Permit should be revised to correctly define normal conditions to ensure correct calculation of the flow rate.

We urge the Department to correct these omissions, ambiguities, and erroneous definitions.

XV. Conclusion

The proposed coal-to-gasoline plant will contribute to harmful air pollution, global warming, and mountaintop removal mining and represents a backward-looking dependence on fossil fuels that is not in the interest of the state, or nation. The Draft Permit issued by the Department does not adequately address these issues, nor does it comply with state and federal air regulations. Among other defects, it omits evaluation of numerous emissions sources at the plant and ignores several types of pollutants completely. An underlying problem is that the Department did not require TransGas to submit sufficient information to support its assumptions and to enable the Department to write enforceable limits for the many restrictions that would be needed to keep this plant below "major source" thresholds — if that is even possible. We urge the Department to deny the permit or, in the alternative, issue a revised draft permit for public review and comment.

---

[202] See, for example, Engineering Toolbox, The definition of STP - Standard Temperature and Pressure and NTP - Normal Temperature and Pressure; http://www.engineeringtoolbox.com/stp-standard-ntp-normal-air-d_772.html, accessed November 23, 2009.

[203] Draft Permit, Condition 4.1.5.5(e).

Respectfully submitted,

Elena Saxonhouse
Sierra Club Environmental Law Program
85 Second St., 2nd Floor
San Francisco, CA 94105
415-977-5765
elena.saxonhouse@sierraclub.org

James Kotcon
Energy Committee
WV Chapter of Sierra Club
414 Tyrone Avery Road
Morgantown, WV 26508
304-293-8822 (office)
304-594-3322 (home)
jkotcon@wvu.edu

on behalf of

Sierra Club
Appalachian Center for the Economy and the Environment
Ohio Valley Environmental Coalition
West Virginia Highlands Conservancy
Coal River Mountain Watch