

**SIERRA CLUB
NATURAL RESOURCES DEFENSE COUNCIL**

January 3, 2012

VIA E-MAIL AND FEDEX OVERNIGHT DELIVERY

Illinois EPA
Dean Studer – Hearing Officer
Re: Christian County Generation
1021 N. Grand Ave. E.
P.O. Box 19276
Springfield, IL 62794-9276
dean.studer@illinois.gov

**RE: Comments on Draft Construction Permit, I.D. No. 021060ACB, for the
Proposed Taylorville Energy Center**

Dear Mr. Studer:

Please accept these comments submitted on behalf of the Natural Resources Defense Council and the Sierra Club (collectively, the “Citizen Groups”) regarding the Illinois Environmental Protection Agency’s (“IEPA”) draft Construction Permit (“Draft Permit”), ID No. 021060ACB, for Christian County Generation LLC’s proposed Taylorville Energy Center (“TEC”), which would convert coal into synthetic natural gas (“SNG”) and electricity. Christian County Generation is a subsidiary of Tenaska Energy, an Omaha, Nebraska based energy developer. As such, we will refer to the project applicant as either “Tenaska” or the “Applicant” throughout these comments.¹

For the reasons set forth below, IEPA must reject Tenaska’s permit application as it fails to meet the requirements of the federal Clean Air Act (“CAA”) and regulations implementing the CAA. If IEPA decides, unwisely and in neglect of its duties, to continue to process Tenaska’s application, IEPA must redraft substantially the permit terms and conditions, re-notice a revised draft permit, and provide the public with a meaningful opportunity to comment on the revised draft permit before any final permit can be issued.

I. INTRODUCTION

¹ These comments were prepared with technical assistance from Phyllis Fox, Ph.D; Camille Marie Sears, MS; Petra Pless, D. Env.; Briana Mordick, MS (NRDC); and George Peridas, Ph.D (NRDC).

Before the Illinois General Assembly and in other contexts, Tenaska seeks to portray the TEC as somehow a “clean” coal plant in an effort to qualify for subsidies under proposed state legislation that, if passed, would force Illinois ratepayers to foot the bill for constructing and operating the multi-billion dollar TEC. Yet the Draft Permit and Tenaska’s permit application tell a far different tale about the TEC and demonstrate that the visions of that plant being somehow “clean” are little more than a mirage.

Most critically, in the context of supporting the state legislation that would subsidize so-called “clean” coal plants, Tenaska has stated on numerous occasions that it would reduce its climate-change inducing carbon dioxide (“CO₂”) emissions through carbon capture and sequestration (“CCS”) or enhanced oil recovery (“EOR”). Yet in the context of this air permitting process, Tenaska claims that such control of CO₂ emissions is far too uncertain to commit to. IEPA blindly accepted such uncertainty claims and, as a result, the TEC would be authorized to emit more than five million tons of CO₂ equivalents every year. In addition, even accepting the emissions underestimations set forth by Tenaska and IEPA, the TEC would emit 696.9 tons of sulfur dioxide (“SO₂”), 228 tons of nitrogen oxides (“NO_x”), 110.7 tons of fine particulate matter, 1,249 tons of carbon monoxide (“CO”), and 90.2 tons of volatile organic matter (“VOM”)² every year. The TEC may be many things but, based on the Draft Permit, clean is not one of them.

A careful review of the record shows that the Draft Permit is legally insufficient in numerous ways, including that IEPA:

- Underestimated flaring emissions of SO₂ and VOM, fugitive particulate matter emissions, and emissions from equipment leaks;
- Failed to establish Best Available Control Technology (“BACT”) emission limits based on the use of cleaner fuels, such as lower sulfur coal or biofuels;
- Failed to require CSS or EOR as BACT for CO₂ emissions from the AGR vent;
- Failed to establish emission limits reflecting BACT for reduced sulfur compounds, pressure relief valves, the flares, the power block, equipment leaks, and materials handling;
- Erroneously concluded that the TEC would not be a major source of hazardous air pollutant emissions;
- Relied on a flawed assessment of the air quality impacts of the TEC that, among other things, failed to ensure that the plant’s emissions would not cause or contribute to exceedances of the one-hour SO₂ National Ambient Air Quality Standard (“NAAQS”), the 24-hour PM₁₀ NAAQS, the 24-hour PM 2.5 NAAQS, or the ozone NAAQS; and

² The Draft Permit fails to define the term VOM but it presumably stands for “volatile organic matter.”

- Failed to ensure that various emission limits and other conditions in the Draft Permit would be practically enforceable.

These and other legal and factual inadequacies in the Draft Permit are discussed more thoroughly below. If IEPA decides to continue processing Tenaska’s permit application (rather than denying it outright), it must remedy each of these inadequacies and issue a revised draft permit for public review and comment.

II. EMISSIONS OF PSD POLLUTANTS WERE UNDERESTIMATED

A. SHORT TERM EMISSIONS OF SO₂ FROM THE FLARE WERE UNDERESTIMATED

Tenaska must demonstrate through modeling that emissions from the TEC would comply with SO₂ Prevention of Significant Deterioration (“PSD”) increments and NAAQS, including the 3-hour and 24-hour PSD increments and the 1-hour, 3-hour, 24-hour, and annual SO₂ NAAQS. Among these, the most difficult to satisfy for this facility is the 1-hour SO₂ NAAQS. Thus, our SO₂ emission evaluation focuses on maximum short-term emissions from flaring.

The worst-case SO₂ emissions occur during startups, shutdowns, and malfunctions when off-specification raw syngas is vented to the flare. The Application estimated emissions for certain “planned startups and shutdowns” but did not estimate them for malfunctions. The following sections first discuss SO₂ emissions during planned startups and shutdowns and then during malfunctions.

1. SO₂ Emissions from Planned Startups and Shutdowns

During startups and shutdowns, there are periods during which raw syngas cannot be fed to the acid gas removal (“AGR”) process, which removes sulfur (“S”) from the syngas, due to process constraints such as elevated temperatures and high particulate concentrations that plug and foul catalyst and adsorbent beds. Thus, this raw syngas is routed directly to the flare for combustion for portions of the startups, shutdowns, and malfunctions. The flare converts sulfur present in the raw syngas as hydrogen sulfide (“H₂S”) and carbonyl sulfide (“COS”) into sulfur dioxide, or SO₂, a PSD regulated pollutant. The Application indicates the number and duration of these events are as summarized here in Table 1.

Table 1
Frequency and Duration of Startup/Shutdown Events^a

Type of Event	No. per Year	Event Duration (hrs)	Total (hrs)
Cold startup	1	65	65
Total plant shutdown	1	60	60
Single gasifier startup	12	29	348
Single gasifier shutdown	12	30	360
Total	26		833

Ap., v. 1, Appx. C, Table C-3, p. C-10.

The Application explains that these are all routine, planned events. The single gasifier startups occur after maintenance outages while the syngas train is still operating, based on a routine maintenance schedule.³ The number and duration of these events are not limited in the Draft Permit. Malfunctions, which are not included in these startup/shutdown events, will be discussed below in Section II.A.2.

The air quality modeling assumed certain maximum one-hour average emission rates in determining the SO₂ air quality impacts of these startup and shutdown events, as summarized here in Table 2. The IEPA modeled the highest SO₂ emission rate reported in this table, or 9,036 lb/hr. However, the Applicant modeled a 1-hour SO₂ emission rate of 9,554 lb/hr. This latter value is not supported in the Application or permit record.

Table 2
Maximum Modeled SO₂ Emissions
Startup/Shutdown Events

Type of Event	SO ₂ (lb/hr)
Cold startup	9,036
Total plant shutdown	8,564
Single gasifier startup	8,628
Single gasifier shutdown	8,565

There are two major problems with these modeled emission rates. First, the Application does not support these emission rates. Information in the record and available from public sources indicates that planned startup and shutdown emissions are significantly underestimated. Second, the Draft Permit does not assure that these SO₂ emission rates will be achieved in practice.

a. Planned Startup/Shutdown Emissions Are Unsupported

The Application lays out a complicated looking formula used to estimate the short-term SO₂ emissions summarized in Table C-3.⁴ However, on inspection, the formula involves only converting the molar flow rates in pound-moles per hour (“lb-mol/hr”) of H₂S (n_{H₂S}) and COS (n_{COS}) into pounds per hour (“lb/hr”) of SO₂, assuming 98% is released at the flare.⁵ The formula reveals nothing about the underlying assumptions, such as coal sulfur content, length of time raw syngas is vented to the flare, composition of raw syngas, etc.

The Application provides no support for the molar flow rates themselves,⁶ which are nothing more than the flared emissions expressed in a different set of units. The equations in the Application⁷ just convert pound-moles per hour into pounds per hour and add in a small amount

³ Ap., v. 1, Sec. 2.2.11, pp. 2-14 to 2-18.

⁴ Ap., v. 1, Appx. C, Table C-3, p. C-8, SO₂ Emissions.

⁵ Ap., v. 1, Appx. C, p. C-13, Table C-3.9.

⁶ Stated without citation in the Ap., v. 1, Appx. C, Table C-3.9, p. C-13.

⁷ See equations in Ap., v. 1, Appx. C, Table C-3, p. C-38, equations listed under heading: “SO₂ Emissions.”

of additional sulfur from the use of supplemental fuel to boost combustion efficiency of this low Btu gas.

The assumptions used to derive the molar flow rates (lb-mol/hr) are not disclosed and thus are unsupported in the permit record. The molar flow rates came from material balances. These material flow rates are not provided in the record. They are based on numerous assumptions that should be subject to agency and public review and specified as permit conditions. These include the design and maximum coal sulfur content, the maximum coal throughput for each hour during the startup/shutdown event, and sulfur retention, if any, in the slag. Because none of the information required to truth the claimed maximum SO₂ emissions was provided, we bounded the likely maximum SO₂ emissions using information scattered throughout the record.

b. Planned Startup/Shutdown Emissions Are Underestimated

The maximum 1-hour SO₂ emissions must be used in the 1-hour SO₂ PSD increment and NAAQS modeling. Our review indicates that the maximum was not used for the reasons discussed below.

i. *Sulfur Conversion Efficiency*

The startup/shutdown flaring calculations assume that only 98% of the sulfur compounds in the flared gases is combusted to form sulfur dioxide (SO₂) and the balance is emitted as the original sulfur compound (H₂S, COS). The 98% assumption is based on unsupported guidance by the Texas Commission of Environmental Quality (“TCEQ”),⁸ rather than measurements at Siemens’s gasification pilot plant in Freiburg, Germany, where hundreds of coal samples have been tested. It is common in permitting to assume 100% conversion of sulfur to SO₂ for potential to emit calculations.⁹ This is especially true and critical where the assumption is not assured through an enforceable permit condition.

The Draft Permit does not require that the flare be designed to achieve no more than 98% sulfur conversion to SO₂, but rather to achieve 98% removal of CO and 99% removal of methanol.¹⁰ In fact, the requirement to achieve 98% CO destruction and 99% methanol destruction are at cross purposes with the requirement to limit sulfur conversion to 98%. The operating procedures include the use of supplemental fuel to improve combustion efficiency, which increases the conversion of sulfur to SO₂.¹¹

⁸ Ap., v. 1, Appx. C, Table C-3, p. C-10 (citing for %CE_{H₂S}: TCEQ, Air Permitting Guidance for Chemical Sources: Flares and Vapor Oxidizers, October 2000).

⁹ For example, in evaluating its proposed coal-to-SNG facility, Power Holdings assumed that all of the H₂S and COS would convert to SO₂ during flaring. See Power Holdings of Illinois, LLC, Flare Emissions – Evaluations (Nov. 5, 2008) at 3, attached as Ex. 1; see also, Emission Estimation Technique Manual for Oil & Gas Exploration & Production, February 1999; http://www2.unitar.org/cwm/publications/cbl/prtr/pdf/cat5/Australia_foilgas.pdf, attached as Ex. 2.

¹⁰ Draft Permit, Cond. 4.1.2-1.a(v).

¹¹ Ap., v. 1, Appx. C, Table C-3, pp. C-8 and C-9 (equation showing Q_{FG} or supplemental fuel, natural gas, which is added to boost combustion).

ii *Total Sulfur Content of Raw Syngas*

The startup and shutdown SO₂ emission calculations assume that the only sulfur compounds present in the raw syngas are H₂S and COS. Traces of other sulfur bearing compounds have been reported in raw syngases including organo-sulfur compounds such as mercaptans and dimethyl sulfide.¹² They cannot be named in this case as the record does not contain complete sulfur characterization data for the syngas but only an unsupported assertion that there are no others.

This is inexcusable as Siemens has tested hundreds of different coals in its pilot scale gasification system in Freiburg, Germany. The raw syngas composition is well known and should be presented in the Application and key components limited in the Permit as the emissions depend directly on syngas composition and measurement is routine. There is no evidence that the Application's calculation of SO₂ emissions during startup and shutdown of the gasifiers took into account *all* sulfur compounds in the gas apart from the unsupported assertion that it did. This claim is impossible to verify with the available information.

iii. *Coal Sulfur Content*

The SO₂ emitted at the flare originates in the coal. During gasification, essentially 100% of the sulfur in the coal is converted into H₂S and COS gases. During normal operation, this sulfur is removed downstream of the gasifiers in the Acid Gas Removal system and ultimately converted into liquid sulfur. However, during cold startups, shutdowns and malfunctions, raw syngas is diverted directly to the flare for a portion of the startup and shutdown, where it is converted into SO₂. This diversion occurs before there is any sulfur removal. Thus, to estimate maximum SO₂ emissions from flaring during non-routine operations, one must know how much coal is gasified during each hour, the amount of sulfur in the coal, and the length of time raw syngas is vented directly to the flare. None of this information is reported in the permit record. Our calculations, summarized below, indicate that the modeled SO₂ emissions are not the maximum 1-hour emissions.

The Application does not disclose the assumed sulfur content of the coal gasified during non-routine operation, rendering the maximum reported SO₂ emissions unsupportable. The only information revealed in the permit record about the coal is: (1) the "design coal supply... would be Illinois Basin coal nominally containing 4.4 percent sulfur by weight";¹³ (2) that it contain at least 1.7 lb sulfur per million British thermal units ("lb/MMBtu") (equal to about 1.7% for a heat content of 10,000 Btu/lb),¹⁴ and (3) that it presumably will be from the Herrin seam, as this coal was used to estimate HAP emissions.¹⁵ It is not clear whether "nominal" is meant to refer to the

¹² Tim Lieuwen, Vigor Yang, and Richard Yetter (Eds.), Synthesis Gas Combustion. Fundamentals and Applications, 2010, Sec. 6.3 and Christopher Higman and Maarten van der Burgt, Gasification, 2nd Ed., Elsevier, 2008, Table 6.2.

¹³ Draft Permit, Findings for Revised Permit, p. 3, Finding c.

¹⁴ Ap., v. 1, p. 5-8.

¹⁵ Ap., v. 1, p. 12-2 and Appx. C, p. C-82, Table C-22.2.

average sulfur content of the coal or the maximum, but either way nothing in the draft Permit suggests that this language establishes an enforceable limit on the maximum sulfur content of the coal to be used at the TEC. At a minimum, IEPA must clarify the maximum coal sulfur content, and make such maximum enforceable.

In addition, to estimate SO₂ emissions at the flare, one must know the amount of coal sent to the gasifier during each hour of the startup, shutdown, and malfunction events. This information is also not disclosed anywhere in the permit record. Thus, there is no basis to conclude that the maximum one-hour SO₂ emissions have been calculated. Our research, outlined below, indicates the proffered maximum 1-hour SO₂ emission rate is far from the maximum potential that must be included in the PSD modeling to satisfy PSD.

We researched Herrin coal, which the Application cites as the basis for HAP emission estimates. The U. S. Geological Survey has studied the subject coal and reports it as well as other Illinois Basin coals as having sulfur content that is “relatively high as compared to other United States coals.” This report characterized the mean sulfur content of Herrin coal as averaging 3.0% and ranging from 0.3% to 14.5%, based on 2,517 samples.¹⁶ Thus, the Applicant has a wide range of coal sulfur contents to choose from.

We estimate the average sulfur content of the coal assumed in the Applicant’s emission calculations is about 3.75%. This is estimated from the ratio of the amount of sulfur leaving the facility to the amount of coal gasified. Assuming no sulfur in the slag¹⁷ and other inputs, the amount of sulfur entering the facility in the coal is equal to the sum of the amount of liquid sulfur produced (190 ton/day)¹⁸ and the amount of sulfur emitted as SO₂, H₂S, and COS, but not derived from fuel firing (e.g., flare pilot, auxiliary boiler) (358.5 ton/yr).¹⁹ The facility is permitted to gasify 1,860,000 ton/yr of coal.²⁰ Thus, the average amount of sulfur in the gasified coal is at least 3.75%,²¹ or about 25% higher than the average for Herrin coal.

The assumed coal sulfur content during non-routine operation is unknown. However, it would not be lower than the average as the BACT analysis concluded (we believe erroneously,

¹⁶ R.H. Affolter and J.R. Hatch, Characterization of the Quality of Coals from the Illinois Basin, Chapter E of: Resource Assessment of the Springfield, Herrin, Danville, and Baker Coals in the Illinois Basin, U.S. Geological Survey Professional Paper 1625-D, p. E-15 and Table 5; http://pubs.usgs.gov/pp/p1625d/508/Chapter_E_508.pdf, attached as Ex. 3.

¹⁷ Coal gasification slags are reported to contain 0.01% to 0.5% sulfur. (See M.S. Najjar and D.Y. Jung, Bench-Scale Test Results and Calculation Procedure for In-Situ Sulfur Capture via Sorbent Addition to Coal Slags under Partial Oxidation, http://www.anl.gov/PCS/acsfuel/preprint%20archive/Files/35_3_WASHINGTON%20DC_08-90_0615.pdf, attached as Ex. 4.) Assuming the maximum slag production rate of 4,500 ton/yr (Ap., v. 1, pdf 302), up to 22.5 ton/yr of sulfur would be partitioned into the slag. This is a very small amount, compared to the amount of sulfur that is partitioned into the various exhaust gases and liquid sulfur product.

¹⁸ Ap., v. 1, Appx. C, p. C-97.

¹⁹ The amount of sulfur emitted, but not derived from fuel firing (e.g., flare pilot, auxiliary boiler, heater), is the sum of the sulfur emitted as SO₂ + H₂S + COS based on the Ap., v. 1, Table 3-2 and Table C-23.1, p. C-86: 32/64(696.87-0.79) + 32/34(8.78) + 32/60(4.11) = **358.5 ton/yr sulfur**.

²⁰ Draft Permit, Cond. 4.1.5-1(a).

²¹ Sulfur content of coal: 100[((190 ton S/day × 365 day/yr) + 358.5 ton S/yr)/1,860,000 ton coal/yr] = **3.75%**.

see Section III.B.3.b below) that the use of low sulfur coals during startup is not feasible.²² We back-calculated the coal sulfur content for the maximum one-hour SO₂ case, 9,036 lb/hr of SO₂, using information scattered about in the Application, Appendix C.

Our calculations indicate that the Application assumed the average annual case coal sulfur content of 3.75% and 60% control efficiency during cold startup, the worst case for SO₂ emissions reported in the Application.²³ The Draft Permit findings indicate the design coal would “nominally” contain 4.4% sulfur as received at the plant.²⁴ Thus, the non-routine emission calculations underestimated SO₂ emissions.

The 60% control efficiency embedded in these calculations is consistent with the BACT analysis which concluded without proof that shifting raw syngas forward as quickly as possible (and the time to do this was not disclosed) would reduce SO₂ emissions for a cold startup event from 170,000 pounds per event (“lb/event”) to 72,000 lb/event or by 60%.²⁵ However, this operating procedure is not required in the Draft Permit or supported by any calculations, test data, or flow diagrams to explain how it would work. If this procedure is not used, or is not successful, the maximum hourly SO₂ emissions correspond to a coal sulfur content of only 2.1%, indicating a significant underestimate. Calculating the maximum hourly emissions assuming average coal sulfur content, without the undocumented and unpermitted feed forward procedure, but otherwise using the Applicant’s assumptions, yields a maximum hourly SO₂ emission rate of $9,036/0.60 = \mathbf{15,060 \text{ lb/hr SO}_2}$ based on 3.75% sulfur (“S”) in the coal.

Alternatively, the Draft Permit does not limit the amount of sulfur in the coal. If the Applicant chose to use a higher sulfur coal than 3.75%, say the “nominal” 4.4% design coal, the maximum SO₂ emissions during a cold startup would increase from 9,036 lb/hr to **10,602 lb/hr**, assuming 60% reduction from the feed forward procedure and **17,670 lb/hr** without the feed forward procedure.

In sum, the worst case coal sulfur content was not used to estimate worst-case, 1-hour SO₂ emissions. Further, an undocumented procedure, forward shifting of raw syngas, was assumed without support, to further lower the maximum 1-hour SO₂ emissions. Thus, we believe the modeling has significantly underestimated maximum 1-hour SO₂ impacts. The sulfur content of the coal burned during startups, shutdowns, and malfunctions can range up to 14.5%. The Permit must be modified to limit the sulfur content of the coal and this limit must be the basis for estimating the maximum 1-hour SO₂ emissions during non-routine operations.

²² Ap., v. 1, p. 6-10.

²³ The amount of coal gasified during the maximum one hour cold start: $[(2,000 \text{ MMBtu raw syngas/hr (Table C-8)}) / (0.0027 \text{ MMBtu/lb raw syngas (p. C-83)})] \times (0.29 \text{ lb coal/lb raw syngas}) \times (\text{ton}/2,000 \text{ lb}) = \mathbf{107 \text{ ton/hr}}$ of coal is gasified during the maximum one-hour cold start, or about half of full production. The gasification of this coal produces 9,036 lb/hr of SO₂. Thus, the sulfur content of the coal would be: $(100)(0.5 \text{ lb S/lb SO}_2)(9,036 \text{ lb SO}_2/\text{hr}) / (107 \text{ ton/hr}) / (2,000 \text{ lb/ton}) = \mathbf{2.11\% \text{ sulfur}}$. If one assumes that 60% of the coal sulfur is removed by the feed forward process described in the Application at 6-6 and converted into liquid sulfur, then the sulfur content of the coal would be $2.11/0.6 = 3.5\%$. This is consistent with the average coal sulfur content estimated elsewhere for a cold startup.

²⁴ Draft Permit, Findings for Revised Permit, p. 3, Finding c.

²⁵ Ap., v. 1, p. 6-6.

iv. *Averaging Time*

The 1-hour SO₂ NAAQS modeling must be based on the maximum amount of SO₂ emitted in any one-hour time period. The maximum value included in the modeling and calculated in Appendix C is 9,036 lb/hr, which occurs during a cold plant startup.²⁶ This value does not correspond to the maximum hour. The Application reports this value as a 3-hour average.²⁷ The IEPA Project Summary also reports this as a 3-hour average.²⁸ This means the value in the maximum hour could be much higher than the 3-hour average, so long as the emission rates in the other two hours are low enough to average it out. For example, the maximum hour could be double the average or 18,072 lb/hr, so long as the other two hours making up the average were half the 3-hour average or $(18,072 + 4,518 + 4,518)/3 = 9,036$ lb/hr.

This scenario is plausible given the Application's claim that a feed forward shift procedure will be used to reduce SO₂ emissions by 60% during cold startups. The Application states: "... sour syngas is fed forward to the shift unit and the shift unit is producing on-specification shifted sour syngas that can be fed to the AGR unit. Once it has determined the raw syngas is of suitable quality to be fed forward, it will bypass the shift unit and will be fed directly to the LTGC unit. This operating practice reduces the SO₂ emission rate during a cold plant startup from more than 170,000 lb/event to less than 72,000 lb/event."²⁹

The Application admits that "... sour unshifted syngas will be flared for a brief duration..." before this shift forward procedure can be implemented,³⁰ but does not disclose the length of that time, nor does the Draft Permit limit the length of time, that raw syngas can be sent to the flare. The hour that includes sending raw syngas directly to the flare would be the maximum 1-hour SO₂ emission rate. If raw syngas is vented to the flare for one full hour, the SO₂ emissions in that hour would be $9,036 \text{ lb/hr} / 0.6 = 15,060$ lb/hr. The value that should be modeled in this case would be 15,060 lb/hr, not the 3-hour average of 9,036 lb/hr.

The Draft Permit establishes 9,036 lb/hr as an hourly limit on total SO₂ emissions from the flare, without stating an averaging time.³¹ However, exceedances of this limit would never be discovered. The Draft Permit does not require any monitoring of SO₂ emissions from the flare. The Draft Permit also does not set limits on any of the parameters required to calculate flaring SO₂ emissions from inputs.

The SO₂ emissions, for example, were calculated in the Application using undisclosed material balances that included coal sulfur content and coal throughput. The Draft Permit does not set limits on these parameters. Alternatively, SO₂ emissions could be calculated from total measured sulfur flow to flare times percent conversion to SO₂. However, the Draft Permit

²⁶ Ap., v. 1, Appx. C, Table C-3.3, p. C-11, column "(max. lb/hr)" for SO₂.

²⁷ Ap., v. 1, p. 6-11.

²⁸ Project Summary, p. 39.

²⁹ Ap., v.1, p. 6-6.

³⁰ Ap., v. 1, p. 6-6.

³¹ Draft Permit, Cond. 4.1.6.b.

requires monitoring only one component of total sulfur sent to the flare, H₂S, rather than H₂S plus COS (reduced sulfur compounds). Omission of COS excludes 13% of the SO₂ from the calculation.

Further, the Draft Permit does not limit the sulfur to SO₂ conversion, assumed to be 98% in the Application, or require that the conversion efficiency be tested, so even if the total sulfur sent to the flare were monitored (H₂S+COS), it could not be used to make an accurate estimate of actual SO₂ emissions from the flare. Greater than 98% conversion of the sulfur to SO₂ is feasible. Under the terms of the Draft Permit, there would be no way to detect higher conversions.

2. SO₂ Emissions from Malfunctions

The Application estimated emissions during one planned cold start, one major facility shutdown, and 12 additional individual planned maintenance gasifier startups and shutdowns per year. These emissions did not include those that occur during malfunctions, which can be substantially higher than during planned events. Thus, the air quality modeling also did not include malfunction events and thus did not model the maximum 1-hour impacts.

A malfunction is any unplanned emergency relief in which the plant operators would have to vent emissions to the flare due to non-routine operating conditions, including the failure or probable failure of equipment that needs to be repaired or exchanged, loss of electrical power, loss of water, or pressure surges, among others. The Application is silent on these types of events.

As malfunctions are unplanned, the duration of the events and the amount and type of emissions could be very different than assumed for the planned startups and shutdowns. If malfunction-related emissions are excluded from the PSD modeling, the offsite ambient SO₂ concentrations will be underestimated. While the Draft Permit does not exclude malfunction events from the flaring emission limits (Condition 4.1.6.b), exceedances of these limits during malfunctions would never be discovered and reported as the testing and reporting are inadequate to detect them. (*See* discussion in Section VII.C below.)

Unplanned releases due to emergency conditions have been widely documented in the coal conversion industry and are not rare occurrences. They occur as a result of harsh processing conditions unique to coal gasification due to high concentrations of substances that corrode, erode and foul processing equipment such as ash, slag, sulfur compounds, and various organic acids. These components cause overheating, plugging, corrosion, erosion, and fouling of common processing equipment such as heat exchangers, coolers, slag handling equipment, and pump, compressor rotors, impellers and blades; fouling and associated corrosion of heat exchangers and coolers.³²

³² Neville A.H. Holt, Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants, Materials at High Temperatures, v. 20, no. 1, pp. 1-6, 2003, attached as Ex. 5; W. Schellberg and others, World's Largest IGCC Celebrates 10th Anniversary, 25th Annual International Pittsburgh Coal Conference, September 29 - October 2, 2008, attached as Ex. 6; EPRI, Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero

In fact, according to a recent presentation, the gasifiers at the Puertollano, Spain IGCC plant experienced unplanned outages in 2007 for 12.8% of the time they would otherwise be available, compared to 8.6% planned outages. The Air Separation Unit (“ASU”), which will also be used at the Taylorville facility, experienced unplanned outages in 2007 of 24.4% compared to planned outages of 1.4%.³³

A reliability study by Siemens for Taylorville indicates poor availability during the first two years of operation, 55-65% during the first year and 75-85% during the second year.³⁴ This indicates the potential for significant malfunction events during these first two years of operation. The facility must comply with all permit limits and not exceed the PSD increments and NAAQS during this period. There has been no demonstration in the permit record that this is feasible.

The permit record does not contain any of the information required to estimate emissions that would occur during these malfunction events. It is likely, for example, that a complete power outage would result in much higher SO₂ emissions than those estimated for the planned cold startup. These maximum emissions must be calculated and included in the modeling. They are known to the Applicant, who would require this information to design the flare, vents and connecting pipelines.

Malfunction emissions have been calculated for other similar projects. For example, the application for the Southeast Idaho Power facility estimated the duration and frequency of events based on whether they were caused by upsets downstream, upstream, or at the acid gas removal unit, estimating a total of 92 hours of upsets per year.³⁵ Likewise, the FutureGen project grouped and estimated upsets by source of the problem: the air separation unit, the gasifier, the acid gas removal unit, the Claus unit, or the power island; it further estimates annual upset frequency for

Emissions, December 2006; Neville A.H. Holt, IGCC Technical Status, Trends and Future Improvements, ACS Meeting, San Francisco, March 2000, attached as Ex. 7.

³³ K. Radtke, M. Heinritz-Adrian, M. Hooper, B. Richards, PRENFLO: PSG and PDQ, Latest Developments based on 10 Years Operating Experience at Elcogas IGCC, Puertollano, Spain, Presentation at Gasification Technologies Conference, Washington, D.C. (October 5-8, 2008), p. 13, attached as Ex. 8; M. Bevilaacqua and others, Monte Carlo Simulation Approach for a Modified FMECA in a Power Plant, *Qual. Reliab. Engng. Int.*, v. 16, 2000, pp. 313-324, attached as Ex. 9.

³⁴ Siemens Operations and Maintenance Reliability Availability Maintenance Analysis, Exhibit 5.5, p. 3. <http://www.icc.illinois.gov/downloads/public/en/Exhibit%205.5%20-%20Siemens%20Operations%20and%20Maintenance%20Reliability%20Availability%20Maintenance%20Analysis.pdf>, attached as Ex. 10.

³⁵ Southeast Idaho Power, Permit Application Appx. D, p. 34. http://www.deq.state.id.us/AIR/permits_forms/permitting/pcaec/app_d_0408.pdf, attached as Ex. 11.

each source type.³⁶ The Medicine Bow project's permit application estimates 40 hours of malfunction-related flaring per year.³⁷

The application for the Power Holdings coal to SNG project in Illinois recognized that upset emissions will occur and made an effort to estimate those emissions. It found that gases sent to the flare during malfunction may be sent without cleanup. The Power Holdings application contains malfunction evaluations at many points, and it attempts to identify the requirements for including malfunction emissions and specific actions for reducing them.³⁸ The Power Holdings application modeled various malfunction scenarios as follows:

The malfunction cases were evaluated in AERMOD. The modeling was conducted for both daytime and nighttime malfunction conditions. The three malfunction scenarios modeled were:

- Malfunction case 4 - Unplanned shutdown of one methanation unit, sweet syngas to SNG flare for 60 minutes.
- Malfunction case 5 - Unplanned shutdown of one Rectisol unit, sour syngas to SNG flare for 22 minutes (modeled as a 60 minute event).
- Malfunction case 6 - Unplanned shutdown of one WSA unit, acid gas to acid gas flare for 22 minutes (modeled as a 60 minute event).
- Malfunction cases 4, 5, and 6 represent the worst case malfunction events. Each malfunction scenario was setup for 23 hours of normal operations with one hour operating under one of the above listed malfunction condition. This operating situation was model as if it occurs every day during the 5 year period. This approached ensured that the highest 2nd high for each PSD review pollutants was identified.³⁹

Malfunction scenarios can be identified and planned for using, for example, fault tree analysis or failure mode effect analysis, to identify possible failure modes in design, operation or maintenance. These types of analyses are used to design the flare system itself. Thus, emissions from malfunctions can be estimated, included in potential to emit calculations, and air quality modeling. However, the permit record in this case does not include the information required to estimate these emissions.

³⁶ FutureGen Final EIS, November 2007, Appx. E, p. E-4, 5.

<http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/Appendix%20E%20-%20Air%20Modeling%20Protocol.pdf>, attached as Ex. 12.

³⁷ Medicine Bow Fuel & Power, LLC PSD Permit Application, Dec. 31, 2007. Appendix B, p. 19, attached as Ex. 13.

³⁸ PSD Construction Permit Application for the Southern Illinois Coal Gasification to Synthetic Natural Gas (SNG) Facility, Prepared for Power Holdings of Illinois, Southern Illinois Coal to SNG Facility, October 17, 2007 ("Power Holdings Permit Application"), Chapters 1 and 2, attached as Ex. 14.

³⁹ Power Holdings Permit Application at 1-130 to 1-131.

To estimate SO₂ emissions during malfunctions, we would need the following information: piping and instrumentation diagrams showing how the flare is connected to specific processing equipment in the plant; the maximum potential flow and worst-case composition of gases from each safety vent venting to the flare and to atmosphere; and the flare design basis (worst-case flare release scenarios and maximum flow rate). With this information, we could complete a calculation of SO₂ and other emissions during malfunctions.

3. Revised Maximum Hourly SO₂ Flaring Emissions

The above discussion indicates that the Application does not estimate the maximum amount of SO₂ that would be emitted at the flare during the worst-case hour. The calculations in the Application are based on a large number of assumptions for planned events, which are either not disclosed at all, or are stated without support. These include: (1) the percent of the sulfur in raw syngas that is converted to SO₂ by combustion in the flare (stated as 98% without support); (2) the sulfur content of the coal gasified during the worst-case hour (not disclosed), or alternatively, the sulfur content of the raw syngas (not disclosed); (3) the coal throughput during the worst-case hour (not disclosed); and (4) the sulfur control achieved by operating procedures (stated as 60% without support). And these assumptions used for planned events may not be valid during malfunction events.

Based on the calculations we present above, the maximum hourly SO₂ emissions could range from **12,048 lb/hr**⁴⁰ if coal containing 5% sulfur were being gasified during the worst case event (instead of the 3.75% assumed in the calculations) to **20,080 lb/hr**⁴¹ if coal containing 5% sulfur were gasified during the worst case event and the operating procedure assumed to reduce emissions by 60% could not be implemented due to emergency conditions. Emissions could be even higher than either end of this range if the flare, supplemented with natural gas as proposed in the Application, converted more than 98% of the sulfur to SO₂ or if even higher sulfur coal were gasified. The Permit would allow either scenario.

B. FLARING VOC EMISSIONS WERE UNDERESTIMATED

Volatile organic material will be emitted from the flare during routine and nonroutine operation. This arises from three sources: (1) pilot; (2) supplementary fuel; and (3) raw syngas. During routine operation, the flare will be equipped with a pilot that will continuously burn 0.34 MMBtu/hr of natural gas. During nonroutine operation, supplemental natural gas fuel will be added to aid combustion. Finally, the gasification process gas itself will contain VOM. These will all be combusted in the flare with an assumed 98% combustion efficiency.⁴²

VOM emissions were underestimated by improper use of an unrelated natural gas boiler emission factor and the presumption that the assumed flare efficiency of 98% would be met at all times.⁴³ Flare combustion efficiency describes how much of a given pollutant is combusted

⁴⁰ Lower end of revised SO₂ flare emission range: (9,036 lb/hr)(5%/3.75%) = **12,048 lb/hr**.

⁴¹ Upper end of revised SO₂ flare emission range: (9,036)(5%/3.75%)/0.6 = **20,080 lb/hr**.

⁴² Ap., v. 1, pp. 2-14, 3-4, 3-5.

⁴³ Ap., v. 1, pp. C-7 to C-14.

relative to the total amount routed to the flare. If hydrocarbons are burned in a flare with a combustion efficiency of 98% (as the Application assumes), 2% of the hydrocarbons would be released directly to the atmosphere. The other 98% is converted into carbon dioxide, carbon monoxide, and water.

The Application estimates flare VOM (0.008 ton/yr) emissions based on this flawed calculation procedure.⁴⁴ Flare VOM emissions were improperly calculated by assuming the behavior of the flare from a combustion standpoint is similar to a natural gas fired boiler, and therefore a natural gas-fired boiler VOM emission factor is appropriate to estimate flare VOM emissions. A natural gas-fired boiler combustion chamber is a highly controlled, contained environment. A flare has no combustion chamber and highly variable gas flow and flare gas composition, and is exposed to conditions, such as crosswinds, that are not present in a natural gas-fired boiler.

C. FUGITIVE PARTICULATE MATTER EMISSIONS (PM, PM10, PM2.5) ARE UNDERESTIMATED

The facility must demonstrate compliance with the 24-hour and annual PSD increments for particulate matter (“PM”) with an aerodynamic diameter of equal to or less than 10 micrometers (“PM10”) or 2.5 micrometers (“PM2.5”), the 24-hour PM10 NAAQS, and the 24-hour and annual PM2.5 NAAQS. Among these, the most difficult to satisfy are the short-term, 24-hour standards. Among the various particulate matter emission sources, those that have the greatest impact are typically fugitive area and volume sources. Thus, our evaluation of particulate emissions focuses on short-term PM10 and PM2.5 emissions from various material handling operations. The modeling analyses must be based on the worst-case, maximum emissions of PM10 and PM2.5 that could be emitted over this averaging period. The PM10 and PM2.5 emissions included in the air quality modeling are not the worst-case, maximum emissions.

Fugitive emissions are those that arise from an area or volume source rather than an elevated stack. These emissions generally result in the highest air quality impacts for PM10 and PM2.5 because they are released near ground level at ambient conditions. The major sources of fugitive material emissions at Taylorville are coal transfer points that are not controlled by baghouses (TP1-3) and the inactive coal storage pile (PIL1). Emissions from other sources of fugitive emissions, such as the slag storage piles, are also underestimated due to the same issues discussed here, but are not revised as they have lesser air quality impacts.

The emissions from these fugitive sources were calculated from empirical formulae published by the U.S. EPA. These formulae require site-specific inputs such as silt content, moisture content, control efficiencies, and various meteorological variables. These input variables were consistently chosen to minimize emissions, which minimized the modeled air quality impacts.

⁴⁴ Ap., v. 1, p. C-7.

Modeled emissions must be based on the maximum anticipated emissions, not the minimum, estimated in the Application. 40 C.F.R. Pt. 51, Appendix W, at Table 8-1 (identifying modeling emission input data for point sources as the “maximum allowable” or “federally enforceable” emission limit multiplied by the “actual or design capacity (whichever is greater)” or a “federally enforceable permit condition”); NSR Manual⁴⁵ at C.45-46. The following sections discuss the errors in the major sources of fugitive material emissions, focusing on short-term emissions. The same errors also exist for long-term annual emissions and other fugitive sources, but they are not explicitly discussed below.

1. Transfer Point Emissions Are Underestimated

The facility includes three points where coal is transferred between conveyors and piles that are not controlled by dust collectors: (1) active storage dome or inactive pile conveyor loadout (TP1); (2) stackout conveyor #3 to inactive pile lowering well (TP2); and (3) inactive pile chain reclaimer to conveyor #4B (TP3).⁴⁶ The emission inventory projected the following potential particulate matter emissions from these three points:

Table 3
Application Transfer Point Emissions⁴⁷
(ton/yr)

Transfer Point	PM	PM10	PM2.5
TP1	0.19	0.089	0.0135
TP2	0.19	0.089	0.0135
TP3	0.0564	0.0267	0.00404

As explained below, these transfer point emissions are significantly underestimated, by over a factor of ten. This affects air quality impacts, discussed in Section IV E. and F. below, as these emissions were included in the air quality impact analysis. The underestimate will never be discovered as the Draft Permit contains no emission limits at all for these sources, no limits on the inputs to the emission calculations (*e.g.*, moisture content, silt content, vehicle miles traveled, coal throughput), nor any monitoring or other compliance provisions to measure these emissions. The proposed emission limits in the Draft Permit for material transfer points TP1-3 in Condition 4.3.2.d and Attachment 1, Table 2, are indicated as “—”. All of the inputs to the emission calculations can be readily measured.

The particulate matter emissions from these three transfer points were calculated in the Application by multiplying an emission factor in pounds per ton (lb/ton) by the maximum actual

⁴⁵ U.S. Environmental Protection Agency, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990 (hereafter “NSR Manual”); The NSR Manual has been used as a guidance document in conjunction with new source review workshops and training and as a guide for state and federal permitting officials with respect to PSD requirements and policy since it was drafted in 1990. Although it is not a binding Agency regulation, the Environmental Appeals Board has looked to the NSR Manual as a statement of the Agency’s thinking on certain PSD issues. *See, e.g., In re ConocoPhillips Co.*, 13 E.A.D. 768, 772 (EAB 2008); *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 542 n.10 (EAB 1999); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n.13 (EAB 1999).

⁴⁶ Ap., v. 1, Appx. C, Table C-9.4, p. C-38.

⁴⁷ Ap., v. 1, Appx. C, Table C-9.5, P. C-39.

annual operating rate of each point in tons per year (ton/yr). These uncontrolled emissions were then reduced using a control efficiency.

a. Emission Factor

The emission factor was estimated from the following empirical expression from the U.S. EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42") Chapter 13.2.4, Aggregate Handling and Storage Piles, for drop emissions:

$$E (\text{lb/ton}) = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$$

where k is a particle size multiplier, U is the mean wind speed, and M is the material moisture content.⁴⁸ The values selected for the input variables U and M both significantly underestimate potential emissions from these transfer points.

i. Mean Wind Speed (U)

These transfer point emissions were estimated assuming a 5-year average wind speed of 8.1 miles per hour ("mph") as measured at the Springfield Capital Airport for the period 2003 to 2007.⁴⁹ The most recent values 5 year of data for 2006 to 2010 indicate the average wind speed at this site is 9.35 mph. This value is used in the revised emission calculations presented below.

ii. Moisture Content (M)

The transfer point emissions were estimated assuming a material moisture content of 11%. The section of AP-42 that the Application relied on reports the moisture content of coal ranges from 2.8% to 11%. The Application picked the upper end of this range, which minimizes emissions. Further, a U.S. EPA document the Applicant relied on to estimate control efficiencies used a material moisture content in this very same equation of 1.85% for bituminous coal, proposed for Taylorville.⁵⁰ The use of an upper-bound moisture content, which minimizes transfer emissions, is inconsistent with the requirement that emission estimates be based on the maximum potential emissions.

The AP-42 source document indicates that "[w]orst-case emissions from storage pile areas occur under dry, windy conditions. Worst-case emissions from material-handling operations may be calculated by substituting into the equation appropriate values for aggregate

⁴⁸ Ap., v. 1, Appx. C, Table C-9.4, p. C-38 and AP-42, Chapter 13.2.4, p. 13.2.4-4; <http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0202.pdf>, attached as Ex. 15.

⁴⁹ Ap., v. 1, Appx. C, Table C-9.2, p. C-36.

⁵⁰ Memorandum from Christian Fellner to Coal Preparation NSPS Docket (EPA-HQ-OAR-2008-0260), Re: Model Plant Control Costing Estimates for Units Subject to the NSPS for Coal Preparation Plants (40 CFR Part 60, Subpart Y), April 2008 ("April 2008 Fellner Memo"), p. 4, bullet 2 (Material Moisture Content: 1.85% (for use in AP-42 fugitive emission factor equation)), attached as Ex. 16.

material moisture content and for anticipated wind speeds during the worst case averaging period, usually 24 hours.”⁵¹

The Draft Permit does not contain any limit on coal moisture content, a value that can be readily measured. Further, other sources indicate much lower moisture contents for Herrin coal. The U.S. Geological Survey (“USGS”) COALQUAL database indicates that the as-received moisture content of 13 coal samples from the Illinois Herrin seam, the coal proposed for Taylorville, ranges from 3.37% to 11.59% and averages 6.48%. Elsewhere, the USGS reports between 1.2% and 22.2% moisture content for Herrin coal from 2,545 samples.⁵² The worst-case potential emissions would occur when coal with the lowest moisture was handled, which is 1.2%. We conservatively used the lower end of the range of the COALQUAL database or 3.37%, which is well within the range of coal moisture contents reported in AP-42.

iii. Control Efficiency

The emission factors in pounds per ton (“lb/ton”) calculated from the above discussed empirical equation were next multiplied by the tons per year of material handled at each transfer point and reduced by an assumed control efficiency achieved through “wet suppression.”⁵³

The emission calculations assumed control efficiencies of 50% for TP1 and TP2 (based on “water spray suppression”)⁵⁴ and 85% for TP3 (based on “inherent chemical latency”).⁵⁵ These control efficiencies are not required as permit conditions and are excessive, given the type of source, required BACT controls, and the assumed very high moisture content. Further, the Draft Permit does not limit the tons per year of material handled at each transfer point, even though this is a critical input in the emission calculations.

The Draft Permit identifies the control technology determination as “wet dust suppression.”⁵⁶ This term is distinguished in the Application from “chemical dust suppression,” suggesting water is implied.⁵⁷ The Draft Permit also indicates that conveyor transfer operations not controlled by filtration devices “shall be sprayed with water or a surfactant solution...”⁵⁸

⁵¹ AP-42, Chapter 13.2, p. 13.2.4-5.

⁵² R.H. Affolter and J.R. Hatch, Characterization of the Quality of Coals from the Illinois Basin, Chapter E of: Resource Assessment of the Springfield, Herrin, Danville, and Baker Coals in the Illinois Basin, U.S. Geological Survey Professional Paper 1625-D, p. E-31, Table 5; http://pubs.usgs.gov/pp/p1625d/508/Chapter_E_508.pdf, attached as Ex. 17.

⁵³ Ap., v. 1, Appx. C, Table C-9.3, p. C-37 (maximum operating rates) and Table C-9.5, p. C-39. See column labeled “emissions control.”

⁵⁴ Ap., v. 1, p. 3-11 and Appx. C, p. C-39, Table C-9, note 1 (National Pollutant Inventory Emission Estimation Technique Manual for Mining Version 2.3, Environment Australia, December 5, 2001, Table 3).

⁵⁵ Ap., v. 1, Appx. C, p. C-39, Table C-9, note 1 (U.S. EPA’s Model Plant Control Cost Estimates for Units Subject to NSPS for Coal Preparation Plants, April 2008).

⁵⁶ Draft Permit, Cond. 4.3.2d.

⁵⁷ See Ap., v. 1, Appx. C, p. C-1, Table C-1.1: “wet dust suppression” is indicated for TP1, TP2, and TP3 while “chemical dust suppression” is indicated for PIL1.

⁵⁸ Draft Permit, Cond. 4.3.5e.

These controls are not adequate to achieve the control efficiencies assumed in the emission calculations.

The section of AP-42 relied on to estimate the empirical emission factor, the starting point for this calculation, cautions that “[w]atering of the storage piles themselves typically has only a very temporary slight effect on total emissions.” “Temporary” and “slight” effects do not constitute 50% to 85% control over the worst-case 24-hour period modeled in the PSD increment and air quality impact analyses.

The AP-42 source document goes on to explain: “A much more effective technique is to apply chemical agents (such as surfactants) that permit more extensive wetting. Continuous chemical treating of material loaded onto piles, coupled with water or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent.”⁵⁹

Further, the April 2008 New Source Performance Standards (“NSPS”) Coal Preparation Plant document used by the Applicant to support the 85% control efficiency for TP-3 indicates that an 85% control efficiency for a transfer point requires full enclosure and inherent chemical latency.⁶⁰ Chemical latency includes continuous application of a surfactant plus a binder. The permitting record is silent on full enclosure of the subject transfer points and surfactants and binders for dust control. This U.S. EPA analysis assumed that all newly constructed transfer points at coal processing facilities would include an enclosure, which was not even evaluated in the Taylorville BACT analysis.

The BACT analysis also did not conclude that continuous chemical treatment was BACT. In fact, it concludes there is no technically feasible measurement method and thus proposes only wet suppression as a work practice standard, enforced pursuant to NSPS Subpart Y by a 10% opacity limit.⁶¹ The record contains no demonstration of the equivalency, if any, between a 10% opacity standard and the modeled PM emissions. Further, this provides no basis at all for assuming 50% to 85% control, which requires the use of chemical suppressants and binds. The *Siemens Operations and Maintenance Operating Cost Assessment Report* does not include any costs for chemical suppressants for dust control, but rather only costs for a “water wagon” which would be used 8 hours per day.⁶²

Further, the Draft Permit does not require a 10% opacity limit. The only transfer point covered by NSPS Subpart Y is TP1.⁶³ No opacity limit at all is required for TP2 or TP3. The PM10/PM2.5 PSD increment and air quality analyses must be based on the maximum 24-hour emissions, not the short-term, best case emissions immediately after a watering event. Thus, a

⁵⁹ AP-42, p. 13.2.4-5.

⁶⁰ April 2008 Fellner Memo (Ex. 16), p. 5, Table 3, p. 7, Table 4, p. 9, Table 5, p. 11, Table 6.

⁶¹ Ap., v. 1, p. 8-11.

⁶² Siemens Operations and Maintenance Operating Cost Assessment Report, Exhibit 5.1, p. 17, <http://www.icc.illinois.gov/downloads/public/en/Exhibit%205.1%20-%20Siemens%20Operations%20and%20Maintenance%20Operating%20Cost%20Assessment%20Report.pdf> (attached as Ex. 18)

⁶³ Ap., v. 1, p. 4-12, Table 4-2.

control efficiency of zero is warranted. However, to be conservative in favor of the Applicant, we have set the control efficiency equal to 50% for all transfer points in calculating revised emissions for modeling.

b. Revised Transfer Point Emissions

We recalculated the emissions, using IEPA’s emission verification spreadsheet, making the changes discussed above. We reduced the moisture content from 11% to 3.37%, increased the wind speed from 8.1 mph to 9.35 mph, and reduced the control efficiency to 50%, based on the absence of any enforceable permit conditions. These changes increase emissions by factors of 13 (TP1, TP2) to 42 (TP3). The revised emissions, compared to those estimated in the Application, are summarized in Table 4.

Table 4
Revised Transfer Point Emissions⁶⁴
(lb/hr)

Transfer Point	PM10 Ap.	PM10 Rev.	PM2.5 Ap.	PM2.5 Rev.
TP1	0.19	1.2172	0.0290	0.184
TP2	0.19	1.2172	0.0290	0.184
TP3	0.0204	0.432	0.00309	0.0654

2. Inactive Coal Storage Pile Emissions (PIL1)

The facility will include two coal storage piles: (1) an active pile located inside a dome that is controlled by a baghouse and (2) an inactive storage pile that is in the open. This section addresses the emission calculations for the inactive storage pile.

At the inactive pile, a chain reclaimer will transfer coal from the pile to a belt conveyor for transport to the crush surge bin. Mobile equipment (dozers/loaders) will keep the inactive storage pile compacted and move coal as required to the chain reclaimer.⁶⁵ The Application identifies three sources of emissions from the inactive storage pile: (1) wind erosion; (2) material transfer by dozers and/or front end loaders, and (3) mobile equipment traffic on unpaved surfaces in the storage yard. The particulate matter emissions from all three of these sources were underestimated, as summarized in Table 5 and discussed below.

⁶⁴ Ap., v. 1, Appx. C, Table C-9.5, p. C-39. The revised (Rev.) emission calculations are in the IEPA emission verification spreadsheet, attached as Ex. 19: PM10 in cells S11, S13, S15 and PM2.5 in cells AN11, AN13, AN15.

⁶⁵ Ap., vol. 1, p. 2-4.

Table 5
Revised Storage Pile Emissions (PIL1)⁶⁶
(lb/hr)

	Wind Erosion	Storage Yard	Material Transfer	Total
PM10 Ap.	0.20	0.29	0.0383	0.53
PM10 Rev.	1.6324	7.2493	1.2172	10.1
PM2.5 Ap.	0.0306	0.292	0.0058	0.33
PM2.5 Rev.	0.245	0.7249	0.1843	1.15

a. Wind Erosion Emissions

Dust (PM, PM10, PM2.5) is generated by wind erosion of open coal storage piles. The Application estimated these emissions using emission factors in pounds per day per acre (“lb/day/acre”)⁶⁷, calculated using an empirical equation from an U.S. EPA reference document, *Control of Open Fugitive Dust Sources*, Section 13.2.4.⁶⁸ A separate equation was used for short-term and long-term (annual) emissions. This emission factor in lb/day/acre was then converted into pounds per hour (lb/hr) by multiplying it by surface area of the pile (600 ft × 600 ft × 45 ft high or 9.74 acres) and converting the units from days to hours.⁶⁹

The following sections discuss only the short-term emission calculations as these were used in the air dispersion modeling. However, the same underestimates discussed below for the short-term emissions are also present in the annual emission calculations.

The emission factor for short-term wind erosion emissions was estimated from the following empirical formula:

$$E_{ST} \text{ (lb/day/acre)} = k \times 1.7 \times (s/1.5) \times (f/15)$$

where k is a particle size multiplier, s is the silt content of the coal in percent, and f is the percent of the time the unobstructed wind speed exceeds 12 mph at the mean pile height. The Application’s choices for the silt content and wind speed variables underestimate wind erosion emissions.

i. *Silt Content*

The inactive storage pile wind erosion emissions included in the modeling assumed an average silt content of 5%, which is consistent with the average silt content reported in AP-42,

⁶⁶ The emission calculations in the Application are found in Vol. 1, Appx. C, p. C-46 (wind erosion), p. C-49 (unpaved storage yard), and p. C-50 (maintenance transfer). The revised calculations are provided in Exhibit 19: storage yard (L79, L80); maintenance transfer (S17, AN17); and wind erosion (W17, AQ17).

⁶⁷ Ap., v.1, Appx. C, p. C-45.

⁶⁸ U.S. Environmental Protection Agency, *Control of Open Fugitive Dust Sources*, EPA-450/3-88-008, September 1988; available at: http://www.primavoce.org/downloads/Control_Of_Fugitive_Dust_Sources.zip (attached as Ex. 20).

⁶⁹ Ap., v. 1, Appx. C, p. C-46 and IEPA Spreadsheet, Tab: Fugitives, Cell U17.

Chapter 13.2, Table 13.2.4-1, for coal (4.6%). However, modeled emissions must be based on worst-case, maximum emissions. The higher the silt content, the higher the emissions. The AP-42 reported silt content of coal ranges up to 7.7%.⁷⁰ Thus, 7.7% is used in the revised emission calculations.

ii. Wind Speeds Greater than 15 mph

The empirical wind erosion equation used to estimate short-term emissions depends upon the percent of the time the unobstructed wind speed exceeds 12 mph at the mean pile height (f factor). The calculations used in the air dispersion modeling assumed 26.66% based on 5 years of data for the period 2003 to 2007 from the Springfield Capital Airport. The most recent 5 year of data for 2006 to 2010 indicates the f factor is higher, 27.7%. This updated value is used in our revised emission calculations.

iii. Control Efficiency

The emissions calculated using the above discussed empirical equation were reduced by 90% based on “spraying chemical suppressants.”⁷¹ The document cited in support of this 90%⁷² explains that chemical suppression means the application of a surfactant plus a binder, as opposed to just a surfactant. A surfactant controls dust from application until the coal is dry while the use of a binder in combination with a surfactant binds the dust particles until the coal is crushed or worked.⁷³

The BACT analysis did not even evaluate chemical suppression for the inactive storage pile, but rather only “wet dust suppression and pile compaction as work practice standards.”⁷⁴ The Draft Permit only requires “wet dust suppression” but does not require any control efficiency whatsoever.⁷⁵ “Wet dust suppression” is not defined in the Draft Permit or anywhere in the Permit record and can include less than continuous application of water, which would result in no reduction in emissions. The Draft Permit does not impose any emission limits at all for any operations at the inactive storage pile, not even on the key variables in the equations used to calculate these emissions, *e.g.*, silt content, pile area, vehicle miles traveled.⁷⁶

As previously explained for transfer emissions, the section of AP-42 that addresses storage piles cautions that “[w]atering of the storage piles themselves typically has only a very temporary slight effect on total emissions.” “Temporary” and “slight” effects do not constitute 90% control over the worst-case 24-hour period. A chemical suppressant coupled with a binder is required to achieve such high control efficiencies.

⁷⁰ AP-42, Table 13.2.4-1.

⁷¹ Ap., v. 1, Appx. C, Table C-12.3, p. C-4, note 2.

⁷² See April 2008 Fellner Memo, Ap., v. 1, Appx. C, Table C-12.3, p. C-46.

⁷³ April 2008 Fellner Memo, p. 2.

⁷⁴ Ap., v. 1, p. 8-18.

⁷⁵ Draft Permit, Cond. 4.3.2.d.

⁷⁶ See Condition 4.3.2.d, Attach. 1, Table II.

The AP-42 storage pile section goes on to explain: “A much more effective technique is to apply chemical agents (such as surfactants) that permit more extensive wetting. Continuous chemical treating of material loaded onto piles, coupled with water or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent.”⁷⁷

Thus, the cited document provides no basis at all for assuming 90% control of wind erosion emissions from the inactive storage pile. The air quality PM10/PM2.5 analysis must be based on the maximum 24-hour emissions, not the short-term, best case emissions immediately after a watering event. Thus, we have set the control efficiencies equal to 50%.

iv. Revised Wind Erosion Emissions

We recalculated the emissions, using IEPA’s emission verification spreadsheet,⁷⁸ making the changes discussed above. We increase the silt content from 5% to 7.7%, increased the f factor from 26.66% to 27.7%, and reduced the control efficiency from 90% to 50%. These changes increase emissions by factors of 8 to 11. The revised emissions, compared to those estimated in the Application and erroneously estimated in the IEPA spreadsheet, are summarized in Table 6.

Table 6
Revised Storage Pile
Wind Erosion Emissions (PIL1)⁷⁹
(lb/hr)

	Wind Erosion Emissions
PM10 Ap.	0.20
PM10 Rev.	1.63
PM2.5 Ap.	0.0306
PM2.5 IEPA	0.0214
PM2.5 Rev.	0.24

3. Inactive Storage Pile Maintenance Transfer Point Emissions (PIL1)

Pile maintenance, moving material onto the pile to maintain its shape for efficient reclaiming, generates fugitive emissions from drop or transfer operations, as discussed below. The inactive storage pile maintenance emissions were calculated in the same manner, using the

⁷⁷ AP-42, p. 13.2.4-5.

⁷⁸ We note that the IEPA verification spreadsheet contains an error for short-term PM2.5 emissions. It used the long term annual equation for wind erosion emissions (in cell AH17). This equation reduces emissions based on the number of days with greater than 0.01 inches of precipitation per year, to estimate short-term emissions in cell AQ17, rather than the equation for short-term emissions, without this term. We corrected this error.

⁷⁹ Ap., v. 1, Appx. C, Table C-12.3, p. C-46 and IEPA Emissions Spreadsheet, Tab: Fugitives, Cells U17 and AN17.

same input assumptions, as previously described for transfer points TP1 to TP3,⁸⁰ and thus contain the same errors previously discussed.

The storage pile transfer emissions are recalculated in Table 7 below, changing mean wind speed (“U”) from 8.1 mph to 9.35 mph; the moisture content (“M”) from 11% to 3.37%; and the control efficiency from 90% to 50%.⁸¹

Table 7
Revised Storage Pile
Maintenance Transfer Emissions (PIL1)⁸²
(lb/hr)

	Material Transfer Emissions
PM10 Ap.	0.0383
PM10 Rev.	1.22
PM2.5 Ap.	0.0058
PM2.5 IEPA	--
PM2.5 Rev.	0.184

a. Unpaved Storage Yard Emissions

Fugitive PM emissions are generated by dozers and loaders travelling in the unpaved storage yard area. The emission factors in pounds per vehicle mile traveled (“lb/VMT”) were estimated using the unpaved haul road equation from AP-42. A separate equation was used for short-term and long-term (annual) emissions. These emission factors were multiplied by an estimate of the miles travelled to calculate emissions in pounds per hour (“lb/hr”) and tons per year (“ton/yr”).⁸³

The following sections discuss only the short-term emission calculations as these were used in the air dispersion modeling. However, the same underestimates discussed below for the short-term emissions are also present in the annual emission calculations.

The emission factor for short-term unpaved storage yard emissions was estimated from the following empirical formula:

$$E = k \times (S/12)^a \times (W/3)^b$$

where E is an emission factor in pounds per vehicle mile traveled, S is the surface material silt content in percent, W is the mean vehicle weight in tons, and the exponents a and b are size-

⁸⁰ Ap., v. 1, Appx. C, Table C-12.8, p. C-50.

⁸¹ In addition to these corrections, the IEPA spreadsheet contains the following two errors, which were also corrected: (1) The PM10 particulate multiplier in cell C17 was incorrectly reported as 0.5. We changed it to 0.35. (2) The spreadsheet did not include any calculations for PM2.5 emissions for this source. We added them.

⁸² Ap., v. 1, Appx. C, Table C-12.3, p. C-46 and IEPA Emissions Spreadsheet, Tab: Fugitives, Cells U17 and AN17.

⁸³ Ap., v. 1, Appx. C, pp. C-47 to C-49, Table C-12 and IEPA Spreadsheet, Tab: Fugitives, Cell U17.

specific constants from AP-42 Table 13.2.2-2.⁸⁴ The resulting emission factors were multiplied by vehicle miles traveled and a control efficiency to estimate emissions in lb/hr and ton/yr. The unpaved storage yard emissions were underestimated due to the choices for silt content and control efficiency, as discussed below.

i. Silt Content

The unpaved storage yard emissions included in the modeling assumed an average surface material silt content of 4.9%, based on the lower end of the range (4.9% -5.3%)⁸⁵ in AP-42, Chapter 13.2.2, for unpaved plant roads at western coal mines. The same AP-42 table reports silt content for other unpaved roads at western coal mines, including haul roads to/from the pit (2.8-18%), scraper route (7.2-25%), and freshly graded haul roads (18-29%).⁸⁶

Modeled emissions must be based on worst-case, maximum emissions. The silt content of coal reported in AP-42, Chapter 13.2.2, ranges up to 29%.⁸⁷ Further, an unpaved storage yard is not similar to a plant road, but rather more like haul roads to and from the pit or freshly graded haul roads as material spills from dozers/loaders and covers the yard.

The permit record contains no basis for selecting the lower end of the plant road silt content range. The Draft Permit contains no limit on silt content of the storage yard or any requirement to test the silt content, a measurement that is easy to make. Thus, we use the upper end of the reported range of 29%. This change alone is sufficient to increase hourly storage yard PM10 emissions from 0.29 lb/hr to 1.45 lb/hr and hourly storage yard PM2.5 emissions from 0.0292 lb/hr to 0.14 lb/hr or by a factor of five.

ii. Control Efficiency

The unpaved storage yard emission calculations assume a control efficiency of 90%, based on spraying chemical suppressant as reported in the *Model Plant Control Cost Estimates for Units Subject to NSPS for Coal Preparation Plants*, as previously discussed for transfer and wind erosion emissions. This control efficiency only applies when both a chemical suppressant and a binder are applied continuously. The Draft Permit only requires wet dust suppression, which, as explained in Section II.C.1.a.iii above, does not achieve any PM10 or PM2.5 reduction over the subject worst-case, 24-hour averaging period, unless it is continuous and includes both surfactant and binder. The Draft Permit does not require any of these conditions. Lowering the control efficiency from 90% to 50% increases hourly storage yard PM10 emissions from 0.29 lb/hr to 1.45 lb/hr and PM2.5 emissions from 0.0292 lb/hr to 0.146 lb/hr, or by a factor of five.

⁸⁴ Ap., v. 1, Appx. C, p. C-47, Table C-12 and AP-42, Section 13.2.2, Equation (1a), p. 13.2.2-4.

⁸⁵ Ap., v. 1, Appx. C, p. C-47, Table C-12 and AP-42, Chapter 13.2.2, Table 13.2.2-1.

⁸⁶ AP-42, Chapter 13.2.2, Table 13.2.2-1.

⁸⁷ AP-42, Chapter 13.2.2, Table 13.2.2-1.

iii. *Omitted Emission Sources*

The emission calculations for the inactive storage pile do not include the emissions from using dozer/loaders to move coal from the pile to the reclaim conveyor.⁸⁸ These emissions are similar to those estimated for bulldozing at western surface coal mines⁸⁹ and are substantial.

b. Revised Unpaved Storage Yard Emissions

The unpaved storage yard emissions are recalculated in Table 8 below, changing the silt content from 4.9% to 29% and control efficiency from 90% to 50%.

Table 8
Revised Storage Pile
Unpaved Storage Yard Emissions (PIL1)
(lb/hr)

	Storage Yard
PM10 Ap.	0.29
PM10 Rev.	7.25
PM2.5 Ap.	0.292
PM2.5 Rev.	0.72

D. **EQUIPMENT LEAK EMISSIONS WERE UNDERESTIMATED**

Equipment leaks are emissions from piping components and associated equipment including valves, connectors, pumps, compressors, process drain, and open-ended lines, as opposed to large point sources of emissions coming from stacks. These components leak small amounts of the gases and liquids they handle through seals and screw fittings. Thus, they are commonly called fugitive emissions or fugitive leaks. These emissions include compounds found in the streams that pass through the components – CO, VOM, H₂S, total reduced sulfur (“TRS”), methane (“CH₄”), carbon dioxide (“CO₂”), and numerous individual hazardous air pollutants (“HAPs”), such as methanol, and carbonyl sulfide (“COS”). The collective leaks from these fugitive components can add up to a large amount of emissions in the aggregate because there are thousands of them. The Taylorville facility is reported to have 24,864⁹⁰ of these components, as follows:

- Connectors: 18,798
- Valves: 5,869
- Pumps: 92
- Sample Connectors: 61
- Compressors: 20

⁸⁸ AP., v. 1, p. 2-4.

⁸⁹ AP-42, Chapter 11.9, Table 11.9-1.

⁹⁰ This total excludes 115 pressure relief valves that are vented to a vapor collection system and burned in the flare.

- Open Ended Lines: 13
- Pressure Relief Valves: 11 (not vented to a flare)⁹¹

The Application claims only very tiny emissions from these 24,864 components, consistent with what one would expect from a facility using state-of-the art leakless and low-leak technology, which is not required for Taylorville:

- CO: 30.51 ton/yr
- VOM: 2.44 ton/yr
- H₂S: 1.42 ton/yr
- Methanol: 1.0 ton/yr
- COS: 1.05 ton/yr
- CO₂: 177.4 ton/yr
- CH₄: 51.3 ton/yr.⁹²

These are tiny amounts, inconsistent with 24,864 uncontrolled components, compared to actual measurements made at any other similar operating facility in allied industries such as refineries and chemical plants, ambient monitoring studies, and emission inventories from a number of other plants. This is an important issue, as the Application eliminates all technically feasible options to control these emissions, arguing that none is cost-effective.

Our revised emissions, discussed in the following sections, indicate that the proposed facility could emit three to seven times more of these pollutants than disclosed in the Application, as follows:

- CO: 118.2 ton/yr
- VOM: 11.8 ton/yr
- H₂S: 6.53 ton/yr
- Methanol: 5.30 ton/yr
- COS: 6.68 ton/yr
- CO₂: 714.7 ton/yr
- CH₄: 155.1

These increases are sufficient to classify the facility as a major source for HAPs, contribute significantly to ozone impacts, and render leakless components and a facility-wide LDAR program cost-effective and thus BACT for equipment leaks.

⁹¹ Ap., v. 1, Appx. C and v. 3, Appx. D.

⁹² *Id.*

Cost-effectiveness or “cost per ton” is the annual cost of control per ton of pollutant removed. It is calculated by dividing the total annual cost of a control method in dollars by the amount of emissions removed by the control in tons per year. The uncontrolled emissions and the emission reductions achieved by the control are key factors in this calculation. If the uncontrolled emissions are underestimated, the cost per ton is overestimated, *i.e.*, dividing a given annual cost by a smaller number yields a higher dollars-per-ton value. The cost per ton to control equipment leak emissions was significantly overestimated by underestimating uncontrolled emission and hence emission reductions. This section explains why the Application underestimates emissions from equipment leaks and corrects these emissions. The revised emissions are used in the next comment to correct the cost-effectiveness analysis in the BACT analysis.

The Application estimated emissions from equipment leaks from three factors: (1) an emission factor for “total emissions”, including all compounds in the mixture; (2) a control efficiency for the “MACT-like” leak detection and repair (“LDAR”) program proposed for a subset of the components; and (3) the weighted average fraction of each pollutant in the total emissions or “speciation” factors. The emission factors, in pounds per hour per component (“lb/hr/component”) for each type of component (valve, pump, compressor, connector, sample connector, open-ended line), were multiplied by the number of components of each type in five sections of the facility. Controlled emissions were then calculated for the high-leak components in two sections of the facility by multiplying total emissions by a control efficiency. The total emissions obtained in this fashion were then multiplied by certain “speciation factors” to estimate the amount of each regulated PSD and HAP pollutant.

The next three sections discuss the emission factors, control efficiencies, and speciation factors used in these calculations. The Applicant underestimated emissions using this approach because it picked the lowest emission factors ever published for equipment leaks from an undocumented source for a non-representative industry, used excessively high control efficiencies, and failed to supported its speciation factors.

1. Equipment Leak Emission Factors

The Applicant chose an undocumented adaptation of the emission factors for total organic compounds (“TOC”) known as SOCOMI (Synthetic Organic Chemical Manufacturing Industry) emission factors.⁹³ These were then used with undocumented chemical speciation data to estimate emissions of individual compounds or groups of compounds. This section discusses the emission factors themselves. The next section discusses converting these into individual pollutant emissions.

The unmodified version of these emission factors was developed by the U.S. EPA based on measurements at 24 chemical plants, producing a range of synthetic organic chemicals.⁹⁴ The

⁹³ Ap., v. 1, Sec. 3.9, p. 3-17.

⁹⁴ U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Report EPA-453/R-95-017, November 1995, Sec. 2.3.1 and Table 2-1 (hereafter “U.S. EPA 11/95”), *available at* www.epa.gov/ttnchie1/efdocs/equiplks.pdf, attached as Ex. 21; U.S. Environmental Protection Agency, Fugitive

adaptation of the U.S. EPA SOCOMI emission factors used in the Application are the lowest possible emissions factors published anywhere that we are aware of for chemical processing plants and do not fairly represent emissions from the proposed facility. When estimating any emissions for purposes of PSD, U.S. EPA emphasizes in the NSR Manual that “[f]or each emissions unit, the estimate should be based on the most representative data available.”⁹⁵

a. SOCMI Factors Are Not Applicable to Gasification Plants

The draft TCEQ guidance that the Application relies on indicates that the SOCOMI factors are generally appropriate for chemical plants.⁹⁶ This draft was never finalized. The U.S. EPA document that these factors were based on identifies polymer and resin manufacturers as the source of the SOCOMI factors.⁹⁷ The polymer and resin manufacturing industry, which manufactures plastics, glues, fiberglass backing material, fiber optics components, and other physical materials, is not similar to coal gasification in terms of types of equipment or feedstocks used. Coal gasification plants are more similar to oil refineries.

Further, SOCOMI emission factors were developed for processes used to generate synthetic organic chemicals such as acetaldehyde, acetone, and phenol,⁹⁸ not for processes used to generate syngas and its byproducts, *e.g.*, air separation, raw syngas production, syngas conditioning, acid gas removal, sulfur recovery, methanation, and dehydration. The amount of TOC emissions from fugitive components depends on the chemicals being processed for many reasons.

Process streams with different chemical (*e.g.*, polarity) and physical properties (*e.g.*, temperature, pressure) will produce different TOC emission factors, *i.e.*, the escaping tendency of chemical inside processing units depends upon the composition of the contained material. The Application and supporting file contain no evidence that the physical and chemical composition of IGCC process streams is similar to that of process streams in the synthetic organic chemical industry. The TOC emission factors developed for synthetic organic chemicals are not relevant to the production of syngas and SNG from coal. The Draft Permit itself makes this clear.

Condition 4.9.4.a excludes the Taylorville components from 40 CFR 60, Subpart VVa “because the SNG and recovered sulfur produced at this plant are not products covered by the SOCOMI NSPS.” Condition 4.9.4.b excludes the Taylorville components from 35 IAC Part 215, Subpart Q “because none of the chemicals produced at the plant are synthetic organic chemicals or polymers listed in 35 IAC Part 215, Appendix D.”

Emission Sources of Organic Compounds – Additional Information on Emissions, Emission Reduction, and Costs, <http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=91009YVL.txt>; Report EPA-450/3-82-010, April 1982 (hereafter “U.S. EPA 4/82”), Sec. 2.1.6 and Table 2-12, attached as Ex. 22.

⁹⁵ NSR Manual, Appendix C, p. 2.

⁹⁶ Texas Commission on Environmental Quality, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000, Draft; attached as Ex. 23.

⁹⁷ U.S. EPA 11/95 and U.S. EPA 4/82.

⁹⁸ See U.S. EPA 4/82, Table 2-12.

Thus, there is no basis at all for applying emission factors developed for these industries, specifically exempted from the Draft Permit, to Taylorville. The Taylorville stream composition data in the Application, Appendix C, pp. C-104 to C-111 indicate that the composition of IGCC process streams is more similar to those found in refineries than in chemical plants.

Coal gasification facilities are not chemical plants, which have had to keep tighter leak standards far longer than other industries as a practical matter due to the extremely hazardous nature and high value of the chemicals they handle. First, SOCOMI facilities handle materials of greater value than those at an IGCC facility, providing an incentive to minimize equipment leaks. Second, a SOCOMI facility typically handles highly toxic and hazardous substances, which must be minimized to prevent worker exposure. These conditions dictate design and operating practices at these facilities to minimize releases. The Application contains no evidence of similar concerns at Taylorville. In fact, it irresponsibly rejects the use of leakless and low-leak technology on the basis of a flawed cost analysis. These components would routinely be used in the synthetic organic chemical industry to preserve feedstock and protect workers. This would result in lower emissions at a SOCOMI facility than at a gasification facility such as Taylorville without similar concerns.

Further, the synthetic chemical industry is largely characterized by smaller equipment and more batch processes that lend themselves more readily to improved control than the processes that would be used at Taylorville. An IGCC plant uses larger equipment operating continuously at higher temperatures. These differences would result in higher emissions from an IGCC facility than from the process units in the synthetic organic chemicals industry that U.S. EPA used to estimate the SOCOMI factors.

In sum, the use of SOCOMI average emission factors as developed by U.S. EPA underestimates TOC and other emissions from the Taylorville facility. However, rather than use even these underestimates, the Applicant selects an unsupported adaptation of these U.S. EPA factors which is lower still than the U.S. EPA SOCOMI factors. This adaptation is discussed in the next section.

b. SOCMI “Without Ethylene” Factor Is Unsupported

Second, rather than using EPA’s average SOCOMI or refinery emission factors, the Applicant selected an adaptation of the SOCOMI factors, used by TCEQ in its draft *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives*.⁹⁹ This guidance was never finalized and the emission factors are undocumented.

These are the lowest emission factors ever proposed for SOCOMI sources. The adaptation used in the Application is called the “SOCMI without ethylene” emission factors. These factors reportedly apply to process lines in SOCOMI plants that contain less than 11% ethylene. However, the relevance of this categorization to leaks from fugitive components in a coal

⁹⁹ Ap., v. 1, Sec. 3.9, p. 3-17, and Texas Commission on Environmental Quality, Emissions Factors for Equipment Leak Fugitive Components, January 2008, available at http://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf, attached as Ex. 24.

gasification plant is unclear and undocumented. The categorization based on the ethylene content of a process stream in a chemical plant is not relevant to the types of gases produced from the gasification of coal and, specifically, ethylene is not a byproduct.

The cited draft TCEQ document and subsequent TCEQ publications contain no support at all for the ethylene-adjusted SOCMi emission factors used for Taylorville. There is no explanation of how TCEQ developed these factors or any analysis of why they are representative of any gasification plant. The average SOCMi and refinery emission factors, on the other hand, are carefully documented in U.S. EPA reports cited above. The average SOCMi and refinery emission factors developed by U.S. EPA, on the other hand, are well documented.¹⁰⁰ Thus, there is no basis for the equipment leak emission factors used for Taylorville.

TCEQ staff indicate the ethylene-adjusted factors were developed from the same data as U.S. EPA used to determine average SOCMi emission factors, but adjusted to exclude ethylene facilities which had higher emissions than other types of chemical plants. TCEQ staff (but not U.S. EPA) assumed this was due to the fact that ethylene is a smaller molecule than others present and therefore more likely to leak in larger amounts from a given size hole. Thus, TCEQ recalculated SOCMi emission factors for volatile organic compounds (“VOC”) for two groups of data: (1) ethylene facilities (the “with ethylene” factors) and (2) all other chemical facilities (the “without ethylene” factors used for Taylorville). TCEQ requires the use of “with ethylene” factors for streams containing greater than 80% ethylene and the lowest factors, “without ethylene,” for streams containing less than 11% ethylene.¹⁰¹

The Application and IEPA assume without any support that process streams at Taylorville will contain only the larger molecules assumed to leak at the smaller rate of the non-ethylene chemical plants.¹⁰² This reasoning does not apply to process streams in gasification plants as they contain high concentrations of compounds smaller in size than ethylene, such as methane, hydrogen and carbon monoxide, which are not present in SOCMi plants in large amounts, if at all, and were not considered in the derivation of the TCEQ factors. Under this reasoning, the higher “with ethylene” emission factors would be more applicable due to the predominance of smaller molecules.

Regardless, it is well known based on measurement studies that VOC emissions from equipment leaks are underestimated by factors of 3 to 20 even when estimated using the conventional U.S. EPA emission factors.¹⁰³ The U.K.’s National Physical Laboratory

¹⁰⁰ U.S. EPA, November 1995 as summarized in Tables 2-1 and 2-2.

¹⁰¹ Email from Texas Commission on Environmental Quality to Phyllis Fox, December 9, 2011, attached as Ex. 25.

¹⁰² Ap., v. 1, Sec. 3.9, p. 3-17 and Ap., v. 1, Appx. C, pp. C-105 to C-111.

¹⁰³ Allan K. Chambers, et al., Direct Measurement of Fugitive Hydrocarbons from a Refinery, *J. Air & Waste Mgmt. Ass’n*, 58:1047-1056 (2008), at 1054 and Table 7, attached as Ex. 26; Clearstone Engineering Ltd., September 6, 2006, attached as Ex. 27; M. Kihlman, et al., *Monitoring of VOC Emissions from Refineries in Sweden Using the SOF Method*, <http://www.fluxsense.se/reports/paper%202%20final%20lic.pdf>, attached as Ex. 28; IMPEL, Diffuse VOC Emissions, December 2000, at p. 38, attached as Ex. 29; U.S. Environmental Protection Agency, Office of Inspector General, EPA Can Improve Emissions Factors Development and Management, Evaluation Report, Report No. 2006-P-00017 (March 22, 2006), pp. 11-12 (summarizing the Texas 2000 Air Quality Study... “This primarily involved under reporting of emissions from flares, process vents, and cooling towers, as well as from fugitive

(equivalent to the U.S. National Institute of Standards and Technology) has compared direct measurements of fugitive VOCs with those estimated by emission factors for over a decade and found the direct measurements were about three times higher than the emission factor estimates on a plant-wide basis.¹⁰⁴ Finally, U.S. EPA auditors have found far more leaks than reported by the facility's program, indicating higher routine emissions than belied by the data.¹⁰⁵

Recent studies confirm the approach used here to estimate fugitive VOC emissions result in significant underestimates in VOC emissions. Monitoring and modeling studies in Texas, the source of guidance used to estimate emissions from several sources in this Application, have demonstrated "severe inconsistencies" between reported and measured emissions. One study concluded: "We believe that our results show that the inventory of industrial VOC emissions [prepared using TCEQ calculation methods] is inaccurate in its location, composition, and emission rates of major sources... Most of the emissions are so-called fugitive emissions from leaking valves, pipes, or connectors, of which there are tens of thousands in a large facility."¹⁰⁶

This conclusion has been confirmed in numerous studies in the past decade, *viz.*, "The analysis presented here for 2000, 2002, and 2006 measurements in the Houston-Galveston-Brazoria area indicates that emission inventory inaccuracies persist."¹⁰⁷ "We conclude that consistently large discrepancies between measurement-derived and tabulated (alkene/NOx) ratios

emissions (leaks). The under-reporting was caused largely due to the use of poor quality emissions factors.") , attached as Ex. 32; U.S. Environmental Protection Agency, VOC Fugitive Losses: New Monitors, Emissions Losses, and Potential Policy Gaps, 2006 International Workshop (October 25-27, 2006), ("VOC Fugitive Losses") p. vii and p. 1 ("emissions from refinery and natural gas operations may be 10 to 20 times greater than the amount estimated using standard emission factors.") , attached as Ex. 31; *Id.*, p. 3 ("Typically, measurements did show some 10 to 20 times higher emissions than calculated at initial measurement activities... Today, after long term experience with the measurements and also after successful improvements of plant operations regarding emissions, emission levels of some 3 to 10 times higher than what is theoretically calculated are typically seen.")

¹⁰⁴ VOC Fugitive Losses, Ex. 31, at. 23. See also results of Swedish studies in this same report at p. 213.

¹⁰⁵ See U.S. EPA's recent refinery settlements at <http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html>.

¹⁰⁶ Ronald C. Henry and others, Reported Emissions of Organic Gases are not Consistent with Observation, Proc. Natl. Acad. Sci., v. 94, June 1997, pp. 6596-6599; available at: <http://www.pnas.org/content/94/13/6596.full.pdf> , attached as Ex. 32a.

¹⁰⁷ R.A. Washenfelder and others, Characterization of NOx, SO₂, Ethene, and Propene from Industrial Emission Sources in Houston, Texas, J. Geophys. Res., v. 115, D16311, 2010, attached as Ex. 33; J.A. de Gouw and others, Airborne Measurements of Ethene from Industrial Sources using Laser Photo-Acoustic Spectroscopy, Environ. Sci. Technol., v. 43, no. 7, 2009, pp. 2437-2442, attached as Ex. 34; B.T. Jobson and others, Hydrocarbon Source Signatures in Houston, Texas: Influence of the Petrochemical Industry, J. Geophys. Res., v. 109, 2004, attached as Ex. 35; T. Karl and others, Use of Proton-transfer-reaction Mass Spectrometry to Characterize Volatile Organic Compound Sources at the La Porte Super Site during the Texas Air Quality Study 2000, J. Geophys. Res., v. 108(D16), 2003, attached as Ex. 36; L.I. Kleinman and others, Ozone Production Rate and Hydrocarbon Reactivity in 5 Urban Areas: A Cause of High Ozone Concentration in Houston, Geophys. Res. Lett., v. 29, no. 10, 2002, attached as Ex. 37; J. Mellqvist and others, Measurements of Industrial Emissions of Alkenes in Texas using the Solar Occultation Flux Method, J. Geophys. Res., v. 115, 2010, attached as Ex. 38; T.B. Ryerson and others, Effect of Petrochemical Industrial Emissions of Reactive Alkenes and NOx on Tropospheric Ozone Formation in Houston, Texas, J. Geophys. Res., v. 108(D8), 2003, attached as Ex. 39; B.P. Wert, Signatures of Terminal Alkene Oxidation in Airborne Formaldehyde Measurements during TexAQS 2000, J. Geophys. Res., v. 108(D3), 2003, attached as Ex. 40.

are due to consistently and substantially underestimated VOC emissions from the petrochemical facilities.”¹⁰⁸ “The results... show that the emissions of ethene and propene, obtained by SOF [solar occultation flux], are on average an order of magnitude larger than what is reported in the 2006 daily EI [Emission Inventory].”¹⁰⁹

A 2006 study reported: “... we do not find good agreement between the measured plume composition and the VOC speciation in the emissions inventory. These observations are not surprising, as previous research has shown that emission fluxes of individual VOCs may be underestimated by as much as 1-2 orders of magnitude in inventories for the Houston area... The frequent lack of correlation between large VOC enhancements and enhancements in SO₂, NO_x and CO suggests large, non-combustion sources of VOCs”¹¹⁰ [*e.g.*, fugitive sources]. One study, for example, reported that measurements of ethene from petrochemical facilities were one to two orders of magnitude higher than reported in the emission inventory.¹¹¹ Monitoring data collected during the 2006 Texas Air Quality Study demonstrated that “[i]ndustrial ethylene and propylene emissions in the NEI05-REF are greatly underestimated relative to the estimates using SOF measurements in the Houston Ship Channel during the study period.”¹¹²

These and other studies have consistently shown based on actual monitoring that emissions estimated using TCEQ emission factors has underestimate VOC emissions by significant amounts. The connection between these long discredited emission factors and an IGCC facility is even more tenuous.

c. Revised Total Emissions

Thus, we calculated uncontrolled total emissions from equipment leaks using other more representative emission factors, including EPA’s average SOCFI factor, TCEQ’s “with ethylene” factor, and EPA’s average refinery factor. We followed the Application’s procedure in every respect except for the underlying emission factors themselves. Our detailed calculations are provided in Exhibit 19 and summarized below in Table 9.

¹⁰⁸ T.B. Ryerson and others (Ex. 39).

¹⁰⁹ J. Mellqvist and others (Ex. 38).

¹¹⁰ Daniel Bon and others, Evaluation of the Industrial Point Source Emission Inventory for the Houston Ship Channel Area Using Ship-Based, High Time Resolution Measurements of Volatile Organic Compounds, CIRES; available at: <http://cires.colorado.edu/events/rendezvous/posters/detail.php?id=3866>, attached as Ex. 41.

¹¹¹ E.B. Cowling and others, A Report to the Texas Commission on Environmental Quality by the TexAQSI Rapid Science Synthesis Team, Prepared by the Southern oxidants Study Office of the Director at North Carolina State University, August 31, 2007, available at: <http://aqrp.ceer.utexas.edu/docs/RSSTFinalReportAug31.pdf>, attached as Ex. 42.

¹¹² S.-W. Kim and others, Evaluations of NO_x and Highly Reactive VOC Emission Inventories in Texas and the Implications for Ozone Plume Simulations during the Texas Air Quality Study 2006, *Atmos. Chem. Phys. Discuss.*, v. 11, 2011, pp. 21,201 - 21,265, available at: <http://www.atmos-chem-phys-discuss.net/11/21201/2011/acpd-11-21201-2011.pdf>, attached as Ex. 43.

**Table 9
Revised Total Emissions from Equipment Leaks***

Component	Service	Number		Emissions (ton/yr)			
		Total	w/LDAR	TCEQ SOCMI w/out C2 Ap., ApxC	EPA SOCMI Average	TCEQ SOCMI w/C2	EPA Refinery Average
Valves	Gas	3,138	304	110.83	164.38	321.28	882.29
	LL	1,195	449	12.42	31.58	162.86	193.48
	HL	1,536	71	4.50	3.28	3.21	3.51
Pumps	LL	47	25	4.37	4.97	16.30	33.94
	HL	45	4	2.91	3.43	0.83	9.54
Compressors	Gas	20	0	44.04	44.04	44.04	136.49
PRVs	Gas	126	0	11.05	11.05	11.05	18.89
Connectors	Gas	12,147	1,165	139.94	193.02	255.75	32.24
	LL	3,283	1,448	4.12	32.92	42.80	27.22
	HL	3,368	148	0.99	39.45	0.69	19.10
Sample Connectors	All	61	16	6.57	6.57	6.57	7.37
Open-Ended Lines	All	13	2	0.20	0.20	0.37	0.28
TOTAL		24,979	3,632	341.92	534.89	865.76	1364.35

Summarized from Ex. 19, Tab RevEm(2).

LL = light liquid; HL = heavy liquid; w/out C2 = without ethylene; w/C2 = with ethylene

First, this table shows that the Application significantly underestimated total emissions from equipment leaks due to the use of an erroneous emission factor. The underestimate is even greater when the other errors, discussed elsewhere in these comments, are factored in, *e.g.*, high control efficiencies inconsistent with the permit conditions, errors in applying control efficiencies, failure to sum emissions for all controlled pollutants, failure to use the correct GHG metric. We did not calculate the impact of these additional factors on facility emissions due to time constraints and incomplete information in the permit record. However, their incorporation would significantly increase the emissions shown in this table, which should be considered as the lower end of the range of emissions from equipment leaks.

The Application's emissions were based on the TCEQ "without ethylene" emission factors for SOCFI "chemical plants," which yield total emissions of 342 ton/yr. This is lower than estimated using all other more representative emission factors. These include two other sets of emission factors for "chemical plants" – the average U.S. EPA SOCFI emission factors (535 ton/yr) and the TCEQ "with ethylene" SOCFI emission factor (866 ton/yr). The highest total emissions from equipment leaks occur when the U.S. EPA average refinery emission factors (1,364 ton/yr) are used.

Gasification plants are more similar to refineries than chemical plants. They both, for example, convert fossil fuels (petroleum, coal) into end products used to generate fuels (gas, gasoline) under similar conditions of pressure and temperature. They both also use many of the

same unit operations, including sour water stripping, sulfur recovery, tailgas treating, sulfur tank and loading, sulfur recovery, thermal oxidizers, and acid gas removal systems.¹¹³

This underestimate is important. The Application concluded that no controls were cost-effective for equipment leaks and eliminated them all as best available control technology (“BACT”). However, cost-effectiveness is just the annual cost-per-ton of pollution removed. If the tons of pollution removed are underestimated, as here, the cost per ton is overestimated. When the revised emissions shown above in Table 9 are used to calculate cost-effectiveness, leakless technology and plant-wide LDAR are both cost-effective for Taylorville.

This underestimate is also important because the total emissions summarized in Table 9 were used to calculate the amount of each regulated PSD and HAP pollutant (*e.g.*, CO, VOM, CO₂, methanol, etc.). Because the starting point, the total emissions, was underestimated, all of the individual pollutants calculated therefrom were also underestimated. This results in a chain reaction of problems, from erroneously rejecting technologies based on cost, to excluding H₂S and reduced sulfur compounds from PSD review, to concluding that Taylorville is a minor source for HAPs. These problems are discussed further below.

Second, this table shows that connectors are the major source of emissions from equipment leaks. The Application excluded connector leaks from its BACT analysis under the theory that their emission factor (lb/hr per connector) was only 70% of the emission factor for other components. However, the Application failed to consider that there are many more connectors in the facility than any other component, so when total connector emissions are calculated from lb/hr per connector times the number of connectors, the contribution of connectors to total emissions is substantial. Thus, the BACT analysis for equipment leaks is fundamentally flawed as it rejected leakless connectors, *i.e.*, welds, as not cost-effective without even including them in the cost analysis.

d. Revised PSD Pollutant Emissions

The Application concluded that PSD review is not triggered for TRS (reduced sulfur compounds) or H₂S as source-wide potential emissions (8.78 ton/yr) are less than the PSD significant emission rate of 10 ton/yr.¹¹⁴ This conclusion is wrong based on the Application’s own emission estimates, as explained in Section III.C. below.

In addition, the revised equipment leak emission calculations confirm that the PSD significance threshold is exceeded for all three reduced sulfur PSD pollutants. Emissions of these PSD pollutants from equipment leaks were underestimated due to the use of the TCEQ “without ethylene” emission factors for chemical plants, as discussed above. Further, as discussed in Section III.C.2 below, COS was erroneously excluded from total reduced sulfur and reduced

¹¹³ Compare *Ap.*, v. 1, Fig. 1-1 and process descriptions in Sec. 2.2 to, *e.g.*, Robert A. Meyers, Handbook of Petroleum Refining Processes, 3rd Ed., McGraw-Hill, 2004; Surinder Parkash, Refining Processes Handbook, Elsevier, 2003; James H. Gary and Glenn E. Handwerk, Petroleum Refining. Technology and Economics, 4th Ed., CRC Press, 2001, 1984; James G. Speight, Synthetic Fuels Handbook. Properties, Process, and Performance, McGraw-Hill, 2008; Christopher Higman and Maarten van der Burgt, Gasification, 2nd Ed., Elsevier, 2008.

¹¹⁴ *Ap.*, v. 1, p. 4-6, Table 4-1.

sulfur compounds emissions. These two errors are corrected in the summary emissions in Table 10. This table shows that PSD review is triggered for H₂S, total reduced sulfur, and reduced sulfur compounds.

Table 10.
Impact of Emission Factor Choice on Sulfur Emissions

Emission Source		Emissions (ton/yr)				
		H ₂ S	Total H ₂ S	COS	Total COS	TRS
All Except Equipment Leaks		7.37	7.37	3.06	3.06	10.43
Equipment Leaks	Ap.	1.41	8.78	1.05	4.11	12.89
	EPA SOCM1	2.34	9.71	1.60	4.66	14.37
	TCEQ w/C2	4.23	11.60	3.85	6.91	18.51
	EPA					
	Refinery	6.53	13.90	6.68	9.74	23.64

Based on Ap., v. 1, Table 3-2 and Ex. 19, Tab H2S&COS. **Bold** indicates exceeds PSD threshold

2. LDAR Control Efficiency

A leak detection and repair program is proposed to control equipment leak emissions from a subset of the components – 3,664 components comprising 15% of the total of 24,979 components. An LDAR program reduces emissions compared to the uncontrolled levels by finding and repairing leaks. The Application concluded that an LDAR program as BACT is “cost infeasible,” but stated that it plans to implement a “MACT-equivalent LDAR program for components in high VOM service in order to reduce VOM emissions by more than 90 percent and 26 tpy.”¹¹⁵ However, the Application itself does not define what it means by “MACT-equivalent.” We studied the supporting emission calculations in the Application’s appendices and conclude that the Draft Permit does not require the LDAR program required to achieve the control efficiencies used in the emission calculations. Further, there is nothing in the Draft Permit to ensure that the installed component and LDAR program will actually achieved the assumed control efficiencies.

The equipment leak emissions were underestimated by assuming much higher control efficiencies for LDAR than required by the Draft Permit. The control efficiency is an estimation of how successful the leak detection and repair program is at finding and fixing leaks. The emission calculations assume a 97% control efficiency for all components except certain pumps, which means only 3% of the emissions remain, compared to what would normally be leaking into the atmosphere if there was no LDAR program.

The control efficiencies used in the Application were taken from draft TCEQ permitting guidance that is based on certain assumptions about how the LDAR program is carried out, *e.g.*, testing frequency, leak detection threshold, time to repair, excluded components. These

¹¹⁵ Ap., v. 1, p. 6-42.

draft TCEQ control efficiencies are unsupported, were not carried over into final guidance,¹¹⁶ and differ substantially from estimates published by U.S. EPA. Further, the Draft Permit fails to require the same level of monitoring assumed in the draft TCEQ guidance to achieve these efficiencies.

Emissions from equipment leaks were calculated by multiplying the uncontrolled emissions by a control efficiency based on the implementation of a LDAR program. The uncontrolled emission factors were calculated from measurements made in chemical plants that did not monitor these emissions. Equipment leak emissions can be reduced by monitoring the components and repairing them when a leak is found. The amount of emission reduction that can be achieved depends on the frequency and method of measurement or observation, the length of time between leak detection and repair, and definition of a leak, *e.g.*, the concentration in parts per million (“ppm”) at which a leak is assumed to occur.

The Application picked the most aggressive control efficiencies that have been proposed anywhere for any type of facility and applied them across the board. The LDAR program must be designed to assure that the assumed control efficiencies are achieved in practice. However, the LDAR program in the Draft Permit is not consistent with the assumptions underlying the assumed control efficiencies.

a. Control Efficiencies Are Unsupported

We were unable to find any support for the assumed control efficiencies. TCEQ personnel informed us that “the original work was done in the mid-80s and there is no formal documentation of the basis in guidance documents.”¹¹⁷ Monitoring studies conducted in Texas have conclusively documented that Texas emission inventories consistently underestimate emissions from leaking components by significant amounts. *See* studies cited *supra*. Thus, barring evidence produced in response to this comment, the Applicant should not be allowed to use these control efficiencies to calculate emissions.

b. Lower Control Efficiencies Apply

The U.S. EPA has published control efficiencies for LDAR programs based on monitoring data and established control efficiencies as part of rulemakings. These are compared to those used in the Application in the following table:

¹¹⁶ Texas Committee on Environmental Quality, Emission Factors for Equipment Leak Fugitive Components, January 2008; http://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/ef_elfc.pdf, attached as Ex. 44.

¹¹⁷ Email from Texas Commission on Environmental Quality to Phyllis Fox, December 13, 2011.

**Table 11
Summary of LDAR Control Efficiencies**

OVA Frequency Physical Inspection Leak Definition	U.S. EPA			TCEQ 28 VHP				Ap. Appx. C
	Monthly ?	Quarterly ?	HON	Quarterly Weekly 2,000 ppm	Quarterly Weekly 500 ppm	Quarterly None	Quarterly Weekly	
Valves Gas	88	70	96		97			97
Valves LL	76	61	95		97			
Valves HL								97
Pumps LL	68	45	88	85				93
Pumps HL								97
Connectors All	NA	NA	81			30	97	
Open-Ended Lines								97
Sample Connectors								97

Summarized from EPA 1995,¹¹⁸ Table 5-3 and TCEQ 10/00, pp. 52-5353, Ex. 19, Tab Cont Eff.

c. Control Efficiencies Are Overestimated for All Fugitive Components

The conditions in the Draft Permit are not adequate to assure that the aggressive control efficiencies in the Application are achieved in practice. One would need a combination of the following in order to achieve high control efficiencies and to confirm emission limits:

- An assessment of BACT for fugitives including installation of sufficient numbers of leakless components, without exemptions for monitoring of these components;
- An audit of the actual leak rates of the facility to compare to those initially assumed, and to develop site specific control efficiencies;
- Limits on the number of inaccessible, difficult-to-monitor, and unsafe-to-monitor components, inclusion of more reasonable, low control efficiencies for these, specific requirements that leaks be fixed at the next turnaround or earlier time period, and inclusion of emissions from these components in total emissions;
- A feedback system to ensure that when the LDAR program detects any leaks, the emissions are included in the total permit limits rather than using pre-determined emissions calculations for in compliance determination.

The Draft Permit does not provide for any of the above actions or systems. Consequently, the Draft Permit provides no assurances that the high control efficiencies assumed will be met.

¹¹⁸ U.S. EPA 11/95 (Ex. 21).

d. Control Efficiencies for Connectors Are Overestimated

The equipment leak emission calculations in the Application assumed a 97% control efficiency for all connectors in services covered by the proposed 28VHP LDAR program.¹¹⁹ However, the allowed control efficiency for connectors under the 28VHP LDAR program is only 30% of the control efficiency assumed in the draft TCEQ guidance and relied upon in the Application. A higher control efficiency is only allowed if the LDAR program meets certain conditions, including weekly inspections and monitoring at the same leak definition as valves.¹²⁰ The Draft Permit does not satisfy these conditions.

First, the Draft Permit does not clearly require weekly physical inspections of connectors, but rather only “routine walk-throughs by operators” (Condition 4.9.2.b and 4.9.7.b), where “routine” is not defined. While Condition 4.9.6.j suggests that weekly physical inspections are intended, the requirement is ambiguous. We suggest that Condition 4.9.6.g be modified to state: “All connectors shall be physically inspected at least weekly.”

Second, the LDAR program in the Draft Permit only requires organic vapor analyzer (“OVA”) monitoring of connectors once per year, while other components that are assigned a 97% control efficiency are monitored quarterly. Thus, assuming the same control efficiency as for valves and pumps likely underestimates connector emissions. Support should be provided for the very high control efficiency for connectors based on only annual monitoring.

Third, the Application concluded VOM BACT for equipment leaks is an emission limit of 2.44 ton/yr, demonstrated by conducting an LDAR program in accordance with the requirements in Exhibit 391-7 to the 391-CAAPP for fugitive emissions in Appendix A.¹²¹ This exhibit contains conditions for connectors that are not present in the Draft Permit including Conditions C (no buried connector unless welded) and E (piping connections shall be welded or flanged, testing of component at operating pressure; weekly visual, audible, and/or olfactory inspections of connectors.).

Thus, the emissions from connectors should be calculated assuming only 30% control, unless the Draft Permit is modified to require weekly inspections and more frequent OVA monitoring. Correcting this error increases total emissions from these connectors from 0.53 ton/yr to 12.5 ton/yr for emissions estimated with the “without ethylene” emission factors and from 1.4 ton/yr to 31.9 ton/yr when estimated with the average SOCFI emission factors.

e. Control Efficiencies Are Inappropriately Applied to Heavy Liquids

The control efficiencies were based on a “non-directed maintenance LDAR program labeled as 28VHP for valves, PRVs, and connectors in gas service and opened ended lines,” based on the draft TCEQ *Air Permitting Technical Guidance for Chemical Sources: Equipment*

¹¹⁹ Ap., v. 1, Appx. C, Tables C-24.2, C-25.2, C-26.2, and C-27.2.

¹²⁰ TCEQ, 10/00, p. 52.

¹²¹ Ap., v. 1, p. 6-52, Sec. 6.6.2.5.

Leak Fugitives.¹²² The draft TCEQ guidance sets out special conditions that must be satisfied to qualify for the 28VHP designation and associated emission reductions. These are not satisfied in either the emission calculations or the Draft Permit conditions.

The emission calculations applied the 28VHP control efficiencies to components in heavy liquid service, even though they are explicitly exempt from LDAR. The 28VHP classification shall not apply where VOC has a vapor pressure of less than 0.044 psia at 68 F¹²³ as the saturation concentration is less than the leak definition, meaning that LDAR would not detect and repair leaks.¹²⁴ Heavy liquids are defined as having a vapor pressure of 0.044 psia or less at 68 F.¹²⁵ Thus, emissions from components designated as in heavy liquid service should not be reduced to account for an LDAR program. Further, the Draft Permit explicitly eliminates these components from the LDAR program.¹²⁶

However, the emission calculations apply the 28VHP control efficiency of 93% to 97% to valves, pumps, and compressors in heavy liquid (triethylene glycol), which the Application properly classifies as “heavy liquid service“ and specifically notes it has a vapor press less than 0.0147 psia.¹²⁷ Thus, the emissions from these components are underestimated. Correcting this error increases total emissions from these components from 0.03 ton/yr to 0.54 ton/yr for emissions estimated with the “without ethylene“ emission factors and from 0.08 ton/yr to 2.3 ton/yr for emissions estimated with the average SOCFI factor.

3. Speciation of SOCFI Emission Factors

The low ethylene SOCFI total emissions were converted into other pollutants by multiplying total emissions by a weighted average concentration of certain chemicals and groups of chemicals found in eight subsets of process streams. The pollutants and pollutant groups are: COS, methanol, hydrogen cyanide (“HCN”), hydrogen chloride (“HCl”), formic acid, CO, H₂S, ammonia (“NH₃”), regulated VOM (never defined, but presumably regulated “volatile organic matter” (ozone-precursor volatile organic matter, including all HAPs), CH₄, CO₂, and certain other unidentified “other volatile or semivolatiles” footnoted to include non-regulated constituents in process fluids which primarily include CH₄, hydrogen (“H₂”), water vapor, and CO₂).¹²⁸ There are a number of problems with these conversions.

First, the Application and supporting permit record contain no support for these weighted average concentrations, which were used to estimate emissions of VOM, CO, CH₄, CO₂, and many HAPs emissions from fugitive components. These were reportedly derived from mass

¹²² See, e.g., Ap., v. 1, Appx. C, Tables C-24.2, C-25.2, C-26.2, and C-27.2, notes 4.

¹²³ TCEQ 10/00, p. 33, Condition A. See also Table 1, which reports that 28 VHP applies only to components with a vapor pressure >0.044 psia at 68 F.

¹²⁴ TCEQ 10/00, p. 14.

¹²⁵ TCEQ 10/00, p. 7

¹²⁶ Draft Permit, Cond. 4.9.2.a(ii).

¹²⁷ Ap., Appx. C, p. C-105, Table C-24.2, note 4.

¹²⁸ Ap., v. 1, Appx. C, pp. C-104 to C-111.

balances, but these mass balances were not produced preventing any meaningful review.¹²⁹ Thus, these emissions are unsupported in the Permit record, and it is evident that IEPA either did not produce the relevant documents or did not itself review the basis for the fugitive emission calculations, based on the documents produced in response to our FOIA request.

Second, the speciated data include two subsets of compounds that are not defined: (1) other volatile or semivolatiles and (2) regulated VOM. Other volatile and semivolatile compounds are defined as to “include non-regulated constituents in the process fluid which primarily include methane (CH₄), hydrogen (H₂), water vapor, and carbon dioxide (CO₂).”¹³⁰ The CH₄ and CO₂ are broken out in Appendix A of Volume 3 of the Application, which contains the GHG BACT analysis, but one is left to guess what additional chemicals might be present.

Regulated VOCs are not defined at all, leaving one to guess what might be included. The PSD VOC parameter is defined at 40 CFR 51.100(s).¹³¹ This definition is subject to legal interpretation as to which specific compounds are included and excluded. As VOC here was estimated from undisclosed material balances, which were not produced, it is not possible to determine if the VOM category used to estimate VOC emissions properly includes all ozone precursor compounds. (The Application refers to this pollutant as VOM, without ever defining it. The regulated PSD pollutant is volatile organic compounds or VOCs, creating ambiguity and uncertainty as to what is included.) For example, it is unclear whether methanol, a HAP, is also included as a VOC, or excluded under the same reasoning used to exclude COS and H₂S from the PSD pollutants total sulfide compounds. (See Section III.C.)

Third, the SOCFI emission factors used as the starting point were not developed specifically for use with inorganic compounds (COS, HCN, HCl, CO, H₂S, NH₃, H₂, CO₂, H₂O), which have very different physical and chemical properties than the total organic compounds measured in the SOCFI studies. These inorganic chemicals make up a significant amount of the emissions from many of the Taylorville process streams. (See, e.g., gasification/syngas condition and methanation process area (18% CO, 11% CO₂); AGR process area (16% CO, 1-6% H₂S, 17-70% CO₂); SRU process area (6-8% CO, 2% NH₃, 20% H₂S, 5% NH₃, 46-47% CO₂), and miscellaneous minor sources (81% CO₂).¹³² The instruments used to measure VOCs in the studies used to develop the SOCFI VOC emission factors did not measure these inorganic species in the process gases.¹³³

The U.S. EPA, for example, clearly notes that “the emission factors and correlations presented in section 2.3 [and used in the Application based on a TCEQ adaptation] are not intended to be applied for the used [sic] of estimating emissions of inorganic compounds. However, in some cases, there may be need to estimate equipment leak emissions of inorganic

¹²⁹ Ap., v. 1, p. 3-17 (“... contacting process stream compositions for all compounds present at detectable levels were calculated based on heat and material balance data.”)

¹³⁰ Ap., v. 1, Appx. C, pp. C-104 to C-111, footnotes.

¹³¹ 40 CFR 52.21(b)(30).

¹³² Ap., v. 1, Appx. C, pp. C-104 to C-111 and v. 3, Appx. A, pp. A-34 to A-38.

¹³³ U.S. EPA 1995.

compounds...The best way to estimate equipment leak emissions of inorganic compounds would be to develop unit-specific correlations as described in section 2.3.4. To do this, it would be necessary to obtain a portable monitoring instrument that could detect the inorganic compounds.”¹³⁴ The Applicant made no documented attempt to determine equipment leak emission factors representative of IGCC process streams, or for the specific inorganic compounds present in them.

III. IEPA AND TENASKA HAVE FAILED TO PROPOSE EMISSION LIMITS THAT REFLECT THE USE OF BEST AVAILABLE CONTROL TECHNOLOGY

The Clean Air Act requires that a permit issued to a major new source of air pollution in an attainment area include emission limits that reflect the installation of BACT for each regulated air pollutant. 42 U.S.C. §§ 7471, 7475(a)(2), 7479(3); 40 C.F.R. 51.21(j)(2). A permit cannot issue without proper BACT limits. 42 U.S.C. § 7475(a)(4); *Alaska Dep’t of Env’tl Conservation v. EPA*, 540 U.S. 461 (2004) (hereinafter “*Alaska DEC*”) (upholding U.S. EPA’s authority to block a PSD permit where the state permitting authority’s BACT determination was unreasonable). The limits proposed in the Draft Permit do not represent BACT because they fail to reflect the maximum emission reductions that are achievable at the TEC.

A. LEGAL BACKGROUND

1. BACT Requires a Thorough and Well-Documented Analysis Aimed At Identifying the Maximum Emission Reductions Achievable.

Under the Clean Air Act, BACT is defined as:

an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

42 U.S.C. § 7479(3). BACT thus requires a case-by-case¹³⁵ analysis in order to determine the lowest emission rate for the pollutant in question for the source in question, reflecting the maximum degree of emissions reduction¹³⁶ that is achievable considering collateral factors such as cost, energy, and other environmental impacts.

By using the terms “maximum” and “achievable,” the Clean Air Act sets forth a “strong, normative” requirement that “constrain[s]” agency discretion in determining BACT. *Alaska*

¹³⁴ U.S. EPA 1995, Sec. 2.4.7, pp. 2-53 to 2-54.

¹³⁵ 42 U.S.C. § 7479(3); NSR Manual, p. B.5.

¹³⁶ NSR Manual, pp. B.1-B.2, B.23.

DEC, 540 U.S. at 485-86. Pursuant to those requirements, “the most stringent technology is BACT” unless the applicant or Agency can show that such technology is not feasible or should be rejected due to specific collateral impact concerns. *Alaska Dep’t of Env’tl. Conserv. v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002). The collateral impacts exception is a limited one, designed only to act as a “safety valve” in the event that “unusual circumstances specific to the facility make it appropriate to use less than the most effective technology.” *In re Kawaihae Cogeneration Project*, PSD Appeal Nos. 96-6, 96-10, 96-11, 96-14, 96-16, 7 E.A.D. 107, 117 (E.A.B. Apr. 28, 1997); *In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm’r 1990) (collateral impacts clause focuses on the specific *local* impacts); *In re Columbia Gulf Transmission Co.*, PSD Appeal No. 88-11, 2 E.A.D. 824, 827 (Adm’r 1989); NSR Manual at B.29. If the Agency proposes permit limits that are less stringent than those for recently permitted similar facilities, the burden is on the applicant and agency to explain and justify why those more stringent limits were rejected. *In re Indeck-Elwood, LLC*, PSD Appeal 03-04, 13 E.A.D.--, slip op. at 77, 79-81 (E.A.B. Sept. 27, 2006); *In re Knauf Fiber Glass, GMBH*, PSD Permit No. 97-PO-06, 8 E.A.D. 121, 131-32 (E.A.B. Feb. 4, 1999). The need to aim for the lowest limits achievable as part of a BACT analysis was recently emphasized by the EAB, which stated in reversing a permit issuance:

If reviewing authorities let slip their rigorous look at ‘all’ appropriate technologies, if the target ever eases from the ‘maximum degree of reduction’ available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.

In re: Northern Michigan University Ripley Heating Plant, PSD Appeal No. 08-02, slip op. at 16 (EAB 2009) (hereinafter “*In re NMU*”); see also *Utah Chapter of Sierra Club*, 226 P.3d at 734-35 (remanding permit where there “was evidence that a lower overall emission limitation was achievable”).

BACT’s focus on the maximum emission reduction achievable makes the standard both technology-driven and technology-forcing.¹³⁷ A proper BACT limit must account for both general improvements within the pollution control technology industry and the specific applications of advanced technology to individual sources, ensuring that limits are increasingly more stringent. BACT may not be based solely on prior permits, or even emission rates that other plants have achieved, but must be calculated based on what available control options and technologies can achieve for the project at issue and set standards accordingly.¹³⁸ For instance,

¹³⁷ NSR Manual, p. B.12 (“[T]o satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control”); pp. B.5 (“[T]he control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams...”); and B.16 (“[T]echnology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.”)

¹³⁸ An agency must choose the lowest limit “achievable.” While a state agency may reject a lower limit based on data showing the project does not have “the ability to achieve [the limit] consistently,” *In re Newmont*, PSD Appeal No. 05-04, 12 E.A.D. 429, 443 (E.A.B. Dec. 21, 2005), it may only do so based on a detailed record establishing an adequate rationale, *see id.* Moreover, actual testing data from other facilities is relevant to establishing what level of control is achievable given a certain technology. *Id.* at *30. The word “achievable” does not allow a state agency to

technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.¹³⁹

The BACT review “is one of the most critical elements of the PSD permitting process” because it determines the amount of pollution that a source will be allowed to emit over its lifetime. *In re Mississippi Lime*, 15 E.A.D. --, slip op. at 17; *In re Knauf*, 8 E.A.D. at 123-24. As such, the BACT analysis must be “well documented” and a decision to reject a particular control option or a lower emission limit “must be adequately explained and justified.” *In re Mississippi Lime*, slip op. at 17; *In re Knauf*. at 131. While the applicant has the duty to supply a BACT analysis and supporting information in its application, “the ultimate BACT decision is made by the permit-issuing authority.” *In re: Genesee Power Station Ltd. Partnership*, 4 E.A.D. 832, 835 (EAB 1993). Therefore, IEPA has an independent responsibility to review and verify Tenaska’s BACT analyses and the information upon which those analyses are based to ensure that the limits in any permit reflect the maximum degree of reduction achievable for each regulated pollutant. *See* 42 U.S.C. § 7479(3) (“permitting authority” makes BACT determination); 40 C.F.R. § 70.7(a)(5).

Information to be considered in determining the performance level representing achievable limits includes manufacturer’s data, engineering estimates, and the experience of other sources.¹⁴⁰ The Applicant and agency must survey not only the U.S. EPA RACT/BACT/LAER Clearinghouse (“RBLC”) database, but also many other sources, both domestic and foreign, including other agencies’ determinations and (draft) permits, permit applications for other proposed plants, technology vendors, performance test reports, consultants, technical journal articles, etc.

2. BACT is Typically Evaluated Through a 5-Step, Top-Down Process

The U.S. EPA established the top-down process described in the NSR Manual in order to ensure that a BACT determination is “reasonably moored” to the Clean Air Act’s statutory requirement that BACT represent the maximum achievable reduction.¹⁴¹ While an agency is not required to utilize the top-down process as laid out in the NSR Manual, where it purports to do so, the process must be applied in a “reasoned and justified manner.” *Alaska Dep’t of Env’tl. Conserv.*, 298 F.3d at 822. As the U.S. Environmental Appeals Board (“EAB”)¹⁴² recently explained:

only look at past performance at other facilities, but “mandates a forward-looking analysis of what the facility [under review] can achieve in the future.” *Id.* at *32. Thus, the agency cannot reject the use of a certain technology based on the lack of testing data for that technology, where the record otherwise establishes that the technology is appropriate as an engineering matter. NSR Manual, at B.5.

¹³⁹ NSR Manual at B.5.

¹⁴⁰ NSR Manual, p. B.24.

¹⁴¹ *Alaska Dept. of Env’tl Conservation v. EPA*, 540 U.S. 461, 485 (2004).

¹⁴² The EAB is the U.S. EPA’s supreme adjudicative body. *See* Changes to Regulations to Reflect the Role of the New Environmental Appeals Board in Agency Adjudications, 57 Fed. Reg. 5320 (Feb. 13, 1992). EAB decisions represent the position of the EPA Administrator with respect to the matters brought before it. *See Tenn. Valley Auth. v. EPA*, 278 F.3d 1184, 1198–99 (11th Cir. 2002) (finding EAB decision to be “final agency action”).

The NSR Manual's "top-down" method is simply stated: assemble all available control technologies, rank them in order of control effectiveness, and select the best. So fixed is the focus on identifying the "top," or most stringent alternative, that the analysis presumptively ends there and the top option selected — "unless" technical considerations lead to the conclusion that the top option is not "achievable" in that specific case, or energy, environmental, or economic impacts justify a conclusion that use of the top option is inappropriate.

In re NMU, slip op. at 13. More specifically, the top-down BACT process typically involves the following five steps:

a. Identify All Available Control Options

The first step in the BACT process is to identify "all potentially available control options." *In re Mississippi Lime*, slip op. at 11. The goal at this step is to cast as wide a net as possible so that a "comprehensive list of control options" is compiled. *In re Knauf*, 8 E.A.D. at 130. As the EAB has emphasized, "available is used in its broadest sense under the first step and refers to control options with a 'practical *potential* for application to the emission unit under evaluation." *Id.* (emphasis in original). A control option is considered "available" if "there are sufficient data indicating (but not necessarily proving)" the technology "will lead to a demonstrable reduction in emissions of regulated pollutants or will otherwise represent BACT." *In re Spokane Regional Waste-to-Energy Applicant*, 2 E.A.D. 809, slip op. at 22 (Adm'r June 9, 1989). The definition of BACT requires that the options considered include "application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant." 42 U.S.C. § 7479(3).

b. Eliminate Technically Infeasible Options.

Step two of the BACT process involves evaluating the technical feasibility of the available options and eliminating those that are not feasible. NSR Manual at B.7; *Indeck-Elwood*, slip op. at 11. Feasibility focuses on whether a control technology can reasonably be installed and operated on a source given past use of the technology. *Id.*; *In re Knauf*, 8 E.A.D. at 130. Feasibility is presumed if a technology has been used on the same or similar type of source in the past. *Id.* This step in the analysis has a purely technical focus and does not involve the consideration of economic or financial factors (including project financing).

c. Rank Remaining Control Technologies by Control Effectiveness

The next step in BACT process is to rank the available and feasible control technologies for each pollutant in order of effectiveness. *In re Mississippi Lime*, slip op. at 12. That is, for each pollutant, the most effective control option is ranked first, and relatively less effective options follow with the least effective option ranked last.

d. Evaluate the Most Effective Controls and Document the Results

The fourth step in the BACT process is to evaluate the collateral economic, environmental and energy impacts of the various control technologies. NSR Manual, B.26; *Indeck-Elwood*, slip op. at 12. This step typically focuses on evaluating both the average and incremental cost-effectiveness of a pollution control option in terms of the dollars per ton of pollution emission reduced. *In re Mississippi Lime*, slip op. at 12. The point of this review is to either confirm the most stringent control technology as BACT, considering economic, environmental, or energy concerns, or to specifically justify the selection of a less stringent technology based on consideration of these factors. *Id.*

e. Select BACT

The final step in the BACT process is to select the most effective control option remaining after Step 4. This option must represent the “maximum degree of reduction... that is achievable” after “taking into account energy, environmental, and economic impacts and other costs.”

B. THE BACT ANALYSIS IMPROPERLY FAILED TO CONSIDER OR REQUIRE CLEANER FUELS

Tenaska’s BACT analysis did not consider cleaner fuels as an alternate feedstock for gasification and argued that they were technically infeasible for short-term use during planned startups and shutdown. Instead, the Application argues that the project is not economic without funding under the Illinois Clean Coal Portfolio Standard Law (the “Clean Coal Act” or “CCA”), which requires the use of coal with at least 1.7 lb S/MMBtu.¹⁴³ This state law impermissibly takes cleaner coal off the table as BACT and thus violates federal PSD regulations.¹⁴⁴ The IEPA adopted Tenaska’s flawed reliance on the CCA and also argued that any other fuel would require redesign of gas treatment and material handling systems and would not result in significantly lower emissions.¹⁴⁵ Neither the Application nor the IEPA Project Summary evaluated cleaner fuels as an option for reducing emissions, but rather argued generally and without support that they are not feasible or would improperly require a redesign of the proposed source.

1. The Clean Air Act Requires an Evaluation of Cleaner Fuels as an Option for Reducing Emissions

IEPA and Tenaska’s refusal to consider cleaner fuels as an option for reducing emissions from the TEC runs contrary to the clearly established requirement that a BACT determination include consideration of “clean fuels.” 42 U.S.C. § 7479(3). As explained above, the fundamental first step in a BACT analysis is to identify all available options for reducing emissions from a proposed source. Such options must include not only add-on controls, but also other “production process and available methods, systems, and techniques.” 42 U.S.C. § 7479(3).

¹⁴³ Ap., v. 1, p. 5-9. See also Project Summary, p. 24 (“The coal feedstock selected by an entity proposing to gasify coal may be critical to the economic feasibility and viability of the proposed project...This is the case for the proposed plant, for which Illinois Basin coal... is the design supply.”).

¹⁴⁴ Ap., v. 1, pp. 5-6 to 5-9.

¹⁴⁵ Project Summary, pp. 24-26.

In 1990, the U.S. Congress added “clean fuels” to the definition of BACT, 42 U.S.C. § 7479(3), in order to codify long time U.S. EPA practice requiring the evaluation of the use of cleaner fuels as an available method for reducing emissions. *In re Inter-Power of New York, Inc.*, PSD Appeal Nos. 92-8 and 92-9, 5 E.A.D. 130, 134 (E.A.B. Mar. 16, 1994). As a result of this amendment, the Clean Air Act “promotes clean fuels with particular vigor.” *In re NMU*, slip op. at 27.

To not evaluate cleaner fuels would “pointedly frustrate congressional will,” *id.*, by reading the phrase “clean fuels” out of the statutory definition of BACT. *Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007). As such, the evaluation of the use of lower sulfur coal and other cleaner fuels is a required part of a BACT analysis. *In re NMU*, slip op. at 17-18; *In re E. Ky. Power Coop., Hugh L. Spurlock Generating Station*, Petition No. IV-2006-4, Order at 30-32 (EPA Adm’r Aug. 30, 2007); *In re Inter-Power*, 5 E.A.D. at 134; *In re Haw. Commercial & Sugar Co.*, PSD Appeal No. 92-1, 4 E.A.D. 95, 99 n.7 (E.A.B. 1992); *In re Old Dominion Elec. Coop.*, PSD Appeal No. 91-39, 3 E.A.D. 779, 794 n.39 (Adm’r 1992).

Where, as here, a cleaner fuel is a technically feasible option for reducing emissions, IEPA and Tenaska may only justify rejecting that cleaner fuel as the basis for BACT emission limits on a proper Step 4 collateral impacts analysis. *See* 42 U.S.C. § 7479(3); *Knauf*, 8 E.A.D. at 131 (agency must fully explain its reasons for rejecting the top control technology based on, among other things, collateral impacts); *In re Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 830 (EAB 1989); *In re CertainTeed Corp.*, 1 E.A.D. 743, 747-49 n.11-12 (EAB 1982) (“general unquantified concerns about collateral impacts, without more, do not justify the rejection of a more stringent technology”); NSR Manual at B.47 – 48. A permitting agency may only sparingly make a finding that a cleaner fuel is not feasible, and only based on circumstances unique to the project. *In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 116-17 (EAB 1997); *see also In re World Color Press*, 3 E.A.D. at 478. Therefore, IEPA’s general assertions about the economic feasibility of using a cleaner fuel are not, by themselves, sufficient to justify rejecting cleaner fuels as a control option for reducing pollutants from the TEC. *See Alaska DEC*, 540 U.S. at 476 (rejecting a BACT analysis where the agency eliminated a control option on claims of economic infeasibility without adequate justification). Rather, clean fuels may be rejected as a pollution control option only if the cost-per-unit of pollutant prevented is disproportionate to the cost per ton incurred by other sources controlling the pollutant in recent BACT determinations. *See In re Masonite Corporation*, PSD Appeal No. 94-1, 5 E.A.D. 551 (EAB 1994).

For a gasification plant like the Taylorville facility, the clean fuels standard may require, among other things, the use of less-polluting feedstocks such as biomass or lower-sulfur coal. Because the BACT analysis fails to properly consider clean fuels, the IEPA Draft Permit is legally deficient.

2. The Use of Cleaner Fuels Would Not Redefine the Source

IEPA attempts to avoid the clean fuels requirement by contending that use of a cleaner fuel would “redefine the source” proposed by Tenaska in two ways.¹⁴⁶ First, IEPA notes that Tenaska “is proposing to develop a plant that would qualify for coverage under the” CCA, a state

¹⁴⁶ Project Summary at 24-26.

law that would effectively require Illinois ratepayers to foot the bill for the construction and operation of the TEC.¹⁴⁷ Because the CCA requires, among other things, that a qualifying plant use bituminous coal with a sulfur content of at least 1.7 lbs/MMBtu, IEPA asserts that requiring the TEC to use a cleaner fuel “would fundamentally alter the business purpose and stated goals of the project” and, therefore, redefine the source.¹⁴⁸ Second, IEPA asserts that the use of a lower sulfur coal feedstock would require changes to the feedstock, gasifier, and syngas conditioning trains that would purportedly redefine the source.¹⁴⁹

IEPA and Tenaska’s reliance on the redefining the source policy is misplaced. The only limit on the Clean Air Act’s clean fuel mandate recognized by the courts is where a fuel change would fundamentally change the physical scope of the project. In other words, the “redefining the source” policy only prevents the permitting agency from requiring the applicant to build a different type of facility- such as substituting a power plant for a municipal waste combustor. *In re Hibbing Taconite Company*, 2 E.A.D. 838, 843 and n.12 (Adm’r 1989). The Administrator in *Hibbing Taconite* explained that a change in fuel type does not redefine the source:

Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project... [The redefining the source] argument has no merit in this case. EPA regulations define major stationary sources by their product or purpose (e.g., “steel mill,” “municipal incinerator,” “taconite ore processing plant,” etc.), not by fuel choice.

Id. (emphasis added). Any other interpretation that avoids more stringent limits based on the applicant’s desires would allow the “redefining the source” exception to swallow the rule that clean fuels must be considered as part of BACT.

The Court of Appeals for the Seventh Circuit has also strictly limited the “redefining the source” policy in a manner contrary to IEPA’s interpretation here. The court held, in the context of a coal-fired power plant, that a permitting agency can decline to evaluate the use of low-sulfur coal only if the plant is sited and designed to receive all of its coal from an adjacent mine that the plant is physically connected to. *Sierra Club*, 499 F.3d at 656.

Here, the TEC is not co-located with a mine and the gasifiers at issue are, as IEPA acknowledges, “feedstock flexible.”¹⁵⁰ In fact, the Summit Power Group has proposed an IGCC facility that would use similar Siemens gasifiers to gasify low sulfur Powder River Basin coal.¹⁵¹ In addition, the purported changes to the feedstock, gasifier, and syngas conditioning trains that IEPA relies on to exclude cleaner fuels appear to be simply the minor changes that the Seventh Circuit has already opined do not constitute redefining the source. In particular, as that Court said:

¹⁴⁷ *Id.* at 24.

¹⁴⁸ *Id.*

¹⁴⁹ *Id.* at 25.

¹⁵⁰ Project Summary at 24.

¹⁵¹ Summit Power Group, Texas Clean Energy Project – The Project, *available at* <http://www.texascleanenergyproject.com/project/>.

[s]ome adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal... but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a control technology.

Sierra Club v. EPA, 499 F.3d at 656. In such cases, BACT must be based on burning the cleaner fuel; otherwise permitting agencies would effectively “read [clean fuels] out of the definition of [best available control technology.]” *Id.* IEPA’s conclusion that the redefining the source policy allows for a different result is plainly contrary to law.

As for the CCA, Tenaska’s desire to qualify as a “clean coal” facility (ironically, by using dirtier coal), does not justify foreclosing the use of cleaner fuels as redefining the source. At most, the ability under the CCA to force Illinois ratepayers to subsidize the TEC might be relevant to the economic analysis of cleaner fuels under Step 4 of the BACT analysis. It does not, however, justify simply ignoring cleaner fuels at the outset of the analysis.

IEPA’s reliance on the CCA fails for a few other reasons. First, while the CCA has been signed into law, the Illinois General Assembly would have to pass additional legislation before Tenaska could force Illinois ratepayers to subsidize its plant. As such, the subsidy that Tenaska and IEPA are relying on here to foreclose evaluation of cleaner fuels is speculative at this point.

Second, to the extent the CCA or other state laws are read to foreclose the consideration of cleaner fuels, such laws run afoul of the Supremacy Clause of the U.S. Constitution, which “invalidates state laws that ‘interfere with, or are contrary to, federal law.’” *Hillsborough County, Florida v. Automated Med. Labs., Inc.*, 471 U.S. 707, 712 (1985). As explained above, the Clean Air Act requires that cleaner fuels be evaluated as a control option during a BACT analysis and be required if the use of cleaner fuels would cost-effectively reduce the emission of regulated air pollutants from a major source of pollution. If the CCA is read to foreclose such evaluation and use of cleaner fuels, then the state law would directly conflict with the Clean Air Act and, therefore, be invalid under the Supremacy Clause. *See, e.g., Clean Air Markets Group v. Pataki*, 338 F.3d 82, 87 (2d Cir. 2003).

Third, IEPA and Tenaska should not rely on the CCA to avoid evaluating and using cleaner fuels because such an interpretation would likely render the coal sulfur content provision of the CCA invalid under the Commerce Clause of the U.S. Constitution. In particular, as Tenaska’s consultant Wood MacKenzie made clear, Tenaska and IEPA are reading the CCA to require that the TEC use Illinois coal and to foreclose the use of coal from other states or regions of the country. Such favoritism of in-state coal and discrimination against out-of-state feedstocks, however, would appear to conflict with the Commerce Clause, which bars economic favoritism between states. *See, e.g., Alliance for Clean Coal v. Miller*, 44 F.3d 591 (7th Cir. 1995); *Alliance for Clean Coal v. Bayh*, 72 F.3d 556 (7th Cir. 1995).

In short, neither the dirtier-coal provision of the CCA nor the relatively minor changes that would be needed for the TEC to operate on cleaner fuels justify dismissing cleaner fuels as somehow “redefining the source.”

3. **Biofuels and Lower Sulfur Coal Are Both Cleaner Fuels That Could be Used to Reduce Emissions from the TEC.**

a. Biofuels

The Application's BACT analysis did not discuss the use of biomass as a feedstock alternative. The IEPA Project Summary, on the other hand, makes four general arguments against biomass: (1) not a suitable feedstock; (2) large-scale farming not feasible; (3) large-scale biomass gasification not feasible; and (4) no improvement in emissions.¹⁵² None of these arguments is supported and none is correct.

First, the Project Summary argues that biomass is not a suitable feedstock for gasification due to its composition and properties. An entire textbook has been devoted to the subject.¹⁵³ Further, the Siemens gasifiers proposed for Taylorville are widely touted by Siemens itself as being able to gasify a wide range of feedstocks, including biomass.¹⁵⁴

One recent example of biomass gasification is the announcement by Progress Energy Florida that it signed another contract with Biomass Gas & Electric LLC ("BG&E") to purchase electricity from a waste-wood biomass plant planned for Florida. This was the second biomass gasification plant that BG&E signed a contract to build, and the company proposes to build a total of four. The Progress Energy plant, which will be built in north or central Florida, will use waste wood products—such as yard trimmings, tree bark, and wood knots from paper mills—to create electricity. The gasification process would supply sufficient gas to generate about 153 MW. The plant will use gasification and projected commercial operation is expected is projected to begin in June 2011. Progress Energy has another biomass project in the Carolina with 73 MW.¹⁵⁵

Second, the IEPA Project Summary asserts, falsely, that farming to produce low quality biomass feedstocks is not available.¹⁵⁶ There is no support for this statement and it is incorrect.¹⁵⁷ Further, there is extensive world-wide precedent for using biomass as part of the feedstock.¹⁵⁸

¹⁵² Project Summary, p. 26.

¹⁵³ Prabir Basu, Biomass Gasification and Pyrolysis: Practical Design, Elsevier, 2010.

¹⁵⁴ Siemens, Integrated Gasification Combined Cycle ("A great advantage of the Siemens fuel gasifier (SFG) is the wide range of fuels it can handle, including coal, biomass, waste, petroleum coke, refinery residues as well as a blend of these fuels."), see <http://www.energy.siemens.com/br/en/power-generation/power-plants/integrated-gasification-combined-cycle/integrated-gasification-combined-cycle.htm#content=Flexibility%20>; Harry Morehead, Gasification Can Play a Key Role in Energy Independence, May 26, 2010, p. 25. <http://www.usea.org/Programs/CCSBriefings/documents/SiemensPresentation-Morehead.pdf>, attached as Ex. 46; Siemens, Siemens Fuel Gasification Technology at a Glance, 2008, p. 4; http://www.dvv.uni-duisburg-essen.de/download/pdf_34Fach/Siemens_P5.pdf, attached as Ex. 47.

¹⁵⁵ See Green Energy News, Florida Public Service Commission (PSC) Approves 20-Year Progress Energy/BG&E Renewable Energy Contract, 2008, Vol. 12 No. 47, February 13, <http://www.green-energy-news.com/nwslinks/clips208/feb08014.html>, attached as Ex. 48; and Progress Energy, Biomass; <https://www.progress-energy.com/commitment/energy-forum/energy-resources/biomass.page>.

¹⁵⁶ Project Summary, p. 26.

Third, the IEPA Project Summary asserts that large scale gasification is not feasible. As discussed above, Siemens, the provider of the gasifiers, asserts they can gasify biomass without any limitation on size.

Finally, the IEPA Project Summary asserts that no improvement in emissions would be achieved as emissions from the Taylorville project are well controlled. This is false, as abundantly demonstrated by the Application itself (and also admitted elsewhere in the Project Summary, at 22). First, startups, shutdowns, and malfunctions will occur, which will send untreated, raw gases directly to the flare without any treatment. While these events only occur during 10% to 15% of the operating hours, the emissions during these events are very high. In these cases, the otherwise good treatment is irrelevant.

These flaring events are the major source of criteria pollutant emissions at the facility, releasing, among others, at least 551 ton/yr of SO₂ and 315 ton/yr of CO.¹⁵⁹ Further, the Taylorville facility will emit over 5 million tons of GHGe, the majority through the uncontrolled AGR CO₂ vent.¹⁶⁰ If low-impact biomass were used to satisfy some or all of the facility's feedstock requirements, the facility would produce fewer emissions of greenhouse gases, hazardous air pollutants, sulfur dioxide, hydrogen sulfide, sulfuric acid mist, and other pollutants.

A proper top-down BACT analysis must consider low-impact biomass inputs into the gasification process as opposed to coal alone. There is already a substantial amount of installed biomass capacity in the country, with forest products and agricultural residues representing potential sources of biomass. And biomass gasification has already been demonstrated as a feasible technology.

In order to satisfy CAA requirements, IEPA must require Taylorville to submit an evaluation of biomass as part of the BACT analyses for the facility. IEPA can allow Taylorville to avoid using biomass only if the company can demonstrate, and IEPA can independently confirm, that the cost of pollutant removal from using such fuel is "disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations."¹⁶¹

¹⁵⁷ New Energy Farms, <http://www.newenergyfarms.com/site/index.php>; Large Scale Production of Biomass in Mozambique for the Dutch Market, <http://www.agentschapnl.nl/en/node/104588>.

¹⁵⁸ Mark Mba Wright Techno-Economic and Environmental Opportunities for Biomass Heat and Power Generation, Prepared for Plains Justice, October 14, 2010, attached as Ex. 135; Co-Firing Biomass with Coal: A Success Story, attached as Ex. 135a; Thermal Net, Workshop on Biomass Co-Processing and Co-Firing, April 5, 2006, attached as Ex. 135b; Mitsui Babcock Biomass Co-Firing Experience from the UK, attached as Ex. 135c.

¹⁵⁹ Ap., v. 1, Table 3-2, Flare.

¹⁶⁰ Ap., v. 3, Table 3-3, Source-Wide Total.

¹⁶¹ NSR Manual, pp. B.31-.32.

b. Lower-Sulfur Coal

The BACT analysis also did not evaluate lower sulfur coal as a feedstock for gasification. Rather, the Application states, without support, that the TEC would not be economically feasible without CCA support, which mandates the use of Illinois Basin Coal with a sulfur content of at least 1.7 lb S/MMBtu.¹⁶² The IEPA Project Summary, on the other hand, asserts that emissions from the gasification process are independent of the composition of the feedstock and depend only on the design and performance specifications for the gasification process.¹⁶³ These arguments are unsupported and incorrect.

First, IEPA claims that use of a different, lower-sulfur feedstock would likely not provide significantly lower emissions.¹⁶⁴ As explained above, however, emissions from the gasification process do depend on the composition of the feedstock. The majority of the SO₂, CO, HAPs, and other emissions occur during startups, shutdowns, and malfunctions when raw untreated or partially treated gases are sent directly to the flare. When this occurs, the design efficiency of the gas treating system is irrelevant. In this case, the composition of the flared gases depends directly on the composition of the feedstock. Substances in the coal are converted into gases in the gasifier. Organic and inorganic sulfur, for example, are converted into SO₂, a gas. Trace metals, such as mercury, lead, and cadmium present in the coal are converted into volatile gaseous forms and emitted in the gases. The majority of the emissions occur during these flaring events. Thus, coal composition has a direct and significant impact on emissions.

For example, the use of a lower sulfur coal would significantly lower SO₂ emissions. The TEC is projected to emit 697 ton/yr of SO₂, with maximum hourly emissions of 9,036 lb/hr. The amount of SO₂ emitted from Taylorville is directly proportional to the amount of sulfur that enters the gasifiers in the coal. The Application did not disclose the sulfur content assumed in the emission calculations. In Section II.A.1.b.iii above, we back calculated that the flaring SO₂ emissions assumed 3.75% sulfur in the coal. The flaring emissions make up 79% of the total SO₂ emissions. Elsewhere, findings in the Draft Permit disclose a nominal coal sulfur content of 4.22%. There are many lower sulfur coals available to the facility.

The facility could import a low sulfur subbituminous coal from the Powder River Basin. Illinois coal-fired electric generators currently import significant amounts of these coals from Wyoming and Montana to meet SO₂ limits.¹⁶⁵ These coals contain very low amounts of sulfur, from 0.5% to 1%. The facility could also use a low sulfur coal from the Illinois Basin. Coals are currently mined from northern and east-central Illinois that contain 1.3% sulfur.¹⁶⁶ If lower sulfur coals were used, the SO₂ emissions would decline from 697 ton/yr to 93 ton/yr¹⁶⁷; if low

¹⁶² Ap., v. 1, p. 5-7.

¹⁶³ Project Summary, p. 22.

¹⁶⁴ Project Summary, p. 25.

¹⁶⁵ Wood Mackenzie Study, Exhibit 19.

¹⁶⁶ Wood Mackenzie Study, Exhibit 60.

¹⁶⁷ SO₂ emissions assuming 0.5% S coal is used: $(697 \text{ ton/yr})(0.5\%/3.75\%) = 92.9 \text{ ton/yr}$. If 4.22% were used as the base: $(697 \text{ ton/yr})(0.5\%/4.22\%) = 82.6 \text{ ton/yr}$.

sulfur PRB coal were used, and to 242 ton/yr¹⁶⁸ if low sulfur Illinois coal were used. The decline in SO₂ emissions would be larger if the Application's emissions were based on the nominal 4.22% sulfur.

Second, the IEPA argues that once a plant has been designed for a specific feedstock, a different feedstock would require the entire gasification block to be redesigned.¹⁶⁹ While some coals may require redesign of portions of the coal handling system or parallel processing trains, there are many similar coals that contain lesser amounts of sulfur than the coal proposed for Taylorville. *See*, for example, the USGS report¹⁷⁰ and Wood Mackenzie Study.¹⁷¹

C. BACT WAS NOT REQUIRED FOR REDUCED SULFUR COMPOUNDS

The pollutants regulated under PSD include hydrogen sulfide (“H₂S”), total reduced sulfur (including H₂S) (“TRS”), and reduced sulfur compounds (including H₂S) (“RS”).¹⁷² The Application¹⁷³ and Project Summary¹⁷⁴ report emissions of total reduced sulfur, reduced sulfur compounds (“RDS”), and hydrogen sulfide as 8.8 ton/yr for H₂S only. This is under the PSD significance thresholds of 10 ton/yr for these pollutants. Thus, the Application and Project Summary conclude that PSD review is not triggered for these pollutants, and no BACT analysis was conducted.

The majority of these emissions originate from flaring, the SRU thermal oxidizer, equipment leaks, and the CO₂ vent stacks. There are technically feasible and cost-effective BACT controls for these three pollutants from these sources, including leakless components, a more comprehensive LDAR program, the use of low sulfur coal during startup and shutdown events, the use of more efficient acid gas controls, and the use of a more efficient flare.

The Application uses two arguments to avoid requiring BACT for these three pollutants. First, it redefines the pollutant to exclude sulfur compounds that it claims are otherwise regulated as HAPs. Second, it argues that emissions of these three pollutants (in each case comprising only H₂S) are under the PSD significance threshold of 10 ton/yr and thus not subject to a BACT analysis. Finally, the Application concatenates the two reduced sulfur compound pollutants – TRS and RDS – treating them identically as though they were a single pollutant. Each of these issues is discussed below.

¹⁶⁸ SO₂ emissions assuming 1.3% S coal is used: (697 ton/yr)(1.3%/3.75%) = 241.6 ton/yr. If 4.22% were used as the base: (697 ton/yr)(1.3%/4.22%) = 214.7 ton/yr.

¹⁶⁹ Project Summary, p. 24.

¹⁷⁰ R.H. Affolter and J.R. Hatch, Characterization of the Quality of Coals from the Illinois Basin, Chapter E of: Resource Assessment of the Springfield, Herrin, Danville, and Baker Coals in the Illinois Basin, U.S. Geological Survey Professional Paper 1625-D, p. E-31, Table 5; http://pubs.usgs.gov/pp/p1625d/508/Chapter_E_508.pdf, attached as Ex. 50.

¹⁷¹ Wood Mackenzie Study, p. 9.

¹⁷² 40 CFR 52.21(b)(23).

¹⁷³ Ap., v. 1, p. 4-6, Table 4-1.

¹⁷⁴ Project Summary, p. 7.

1. The Draft Permit Improperly Redefines the Pollutant

The federal PSD regulations at 40 CFR 52.21 do not define the terms: total reduced sulfur (including H₂S) and reduced sulfur compounds (including H₂S). The Application argues that total reduced sulfur and reduced sulfur compounds consist of the sum of H₂S, COS, and carbon disulfide (“CS₂”), citing a definition from NSPS Subpart J, 40 CFR 60.101 for refineries, promulgated prior to the original August 1980 PSD rules. The Application next asserts that as COS and CS₂ are HAPs regulated under the MACT rules, they cannot be simultaneously regulated under the PSD program.¹⁷⁵

Why would EPA designate two separate pollutants for reduced sulfur compounds that contained exactly the same three compounds? The very fact that they exist as separate PSD pollutants indicates that this interpretation is wrong. Material in the docket of the original 1980 PSD rulemaking indicates that at the time that the PSD regulations were promulgated, the EPA assumed that total reduced sulfur consisted of hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide or simply hydrogen sulfide plus reduced organic sulfur compounds. Reduced sulfur compounds consisted of hydrogen sulfide, carbon disulfide and carbonyl sulfide or simply inorganic reduced sulfur compounds.¹⁷⁶ There is no basis for assuming that these two separate pollutants consist of exactly the same three compounds based on a definition from 40 CFR 60.101 for refineries.

Definitions in other sections of 40 CFR confirm that these are separate pollutant as follows:

- “Reduced sulfur compounds“ is defined at 40 CFR 60.641 – Definitions
Reduced sulfur compounds means H₂S, carbonyl sulfide (COS), and carbon disulfide (CS₂).
- “Total reduced sulfur“ is defined at 40 CFR 60.281 – Definitions
Total reduced sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide, that are released during the kraft pulping operation and measured by Method 16.

Thus, reduced sulfur compounds and total reduced sulfur are two separate pollutants, containing different reduced sulfur compounds, and having only hydrogen sulfide in common. The Application erred by assuming these were the same pollutant and replacing them with only hydrogen sulfide.

Further, there is no legal or technical basis to piecemeal a regulated pollutant, such as total reduced sulfur and reduced sulfur compounds, stripping them into parts and treating each differently. The subject pollutants, total reduced sulfur and reduced sulfur compounds, were

¹⁷⁵ Ap., v. 1, p 3-2, Table 3-1, notes 4 and 5 and p. 4-4.

¹⁷⁶ U.S. Environmental Protection Agency, Impact of Proposed and Alternative *De Minimis* Levels for Criteria Pollutants, Report EPA-450/2-80-072, June 1980, Tables 1 and 2, cited at 45 FR 52706 (Aug. 7, 1980).

listed as PSD pollutants as groups, primarily to avoid nuisance (odor) problems,¹⁷⁷ not as a collection of individual compounds to prevent health effects. Thus, there is no basis for pulling apart the group and arguing that part of it is regulated elsewhere due to health impacts. In this sense, total reduced sulfur and reduced sulfur compounds are no different than VOCs, which are regulated as ozone precursors under the NSR program while select members of the VOC group are also regulated as HAPs. In applying NSR, one does not subtract VOC HAPs from ozone-precursor VOCs, as different aspects of the compounds are being regulated under each rule.

Further, pulling apart reduced sulfur groupings makes no sense as individual members of each of these group interact, resulting in more significant impacts together than one at a time. Regardless, even assuming a regulated pollutant such as total reduced sulfur could be piecemealed based on duplicate regulation; in this case, these compounds in fact are not regulated under MACT as the Applicant claims this facility to be a minor source not subject to MACT.

2. Reduced Sulfur Compounds Exceed the PSD Significance Threshold

PSD review is triggered for reduced sulfur compounds (“RDS”) if emissions of RDS equal or exceed 10 ton/yr. 40 CFR 52.21(b)(23)(i). As discussed above, reduced sulfur compounds consist of the sum of inorganic reduced sulfur compounds, including carbonyl sulfide and carbon disulfide.

The emission calculations in the Application indicate that total facility-wide emissions of reduced sulfur compounds are:

- H₂S: 8.78 ton/yr
- COS: 4.11 ton/yr
- CS₂: 0.00894 ton/yr
- **Total: 12.9 ton/yr**

Thus, the emission calculations in the Application itself indicate that reduced sulfur compounds exceeds the PSD significance threshold of 10 ton/yr, requiring a BACT analysis. The applicant apparently crafted the piecemealing argument, removing COS and CS₂ from the reduced sulfur compound pollutant, to avoid triggering PSD for reduced sulfur compounds.

Further, the Application’s estimate of 12.9 ton/yr of reduced sulfur compounds is an underestimate due to errors in its estimates of emissions from some of the contributing sources, as discussed elsewhere in these comments.

¹⁷⁷ 45 FR 52676 at 52709 (Aug. 7, 1980) (“Total Reduced Sulfur, Reduced Sulfur – These pollutant classes include hydrogen sulfide (H₂S) and are regulated primarily to avoid nuisance (odor) problems”).

3. Total Reduced Sulfur Compounds Exceed the PSD Significance Threshold

PSD review for total reduced sulfur compounds is triggered if emissions of TRS equals or exceeds 10 ton/yr.¹⁷⁸ As discussed above, reduced sulfur compounds consists of the sum of hydrogen sulfide, dimethyl sulfide, and dimethyl disulfide or simply hydrogen sulfide plus reduced organic sulfur compounds. The Application did not estimate the emissions any reduced organic sulfur compounds which are present in facility emissions.

Gasification facilities emit reduced organo-sulfur compounds, including mercaptans and dimethyl sulfide,¹⁷⁹ which are not HAPs and thus cannot be dismissed even under the Applicant's erroneous piecemealing argument. Thus, emissions of these compounds should have been included in the emission inventory. Correcting just the errors in the equipment leak emissions, emissions of total reduced sulfur compounds exceed 10 ton/yr because hydrogen sulfide is explicitly included in this pollutant and its emissions increase from 8.78 ton/yr reported in the Application up to 13.9 ton/yr when EPA's refinery emission factors are used to estimate equipment leaks (Section II.D.1.d.) Thus, PSD review, including a BACT analysis is required for total reduced sulfur compounds. This review must include an estimate of emissions of all compounds included in this pollutant.

D. BACT WAS NOT REQUIRED FOR CO₂ EMISSIONS FROM THE AGR VENT

The gasification block includes two Siemens gasifiers that convert coal into a synthesis gas or "syngas." This syngas is processed to remove contaminants and prepare it for conversion into substitute natural gas. The substitute natural gas is then either converted into electricity or sold to others. The additional processing of the syngas includes particulate removal, a carbon bed to remove mercury, and acid gas removal followed by sulfur recovery to remove sulfur compounds. However, these processes do not remove CO₂, which is vented uncontrolled from the AGR vent. This is the major source of greenhouse gas emissions from Taylorville. The Application does not require any control for CO₂ emissions from the AGR vent and thus fails to satisfy BACT.

1. IEPA Improperly Eliminated Carbon Capture and Storage as BACT for CO₂

IEPA and Tenaska have failed in their duty to evaluate carbon capture and sequestration ("CCS") as part of their BACT analysis. Although CCS receives cursory discussion as part of top-down BACT, it is promptly brushed off as infeasible for a host of vague, unsupported, and – upon more thorough analysis – wrong reasons. This failure to properly evaluate CCS is of

¹⁷⁸ 40 CFR 52.21(b)(23)(i).

¹⁷⁹ Tim Lieuwen, Vigor Yang, and Richard Yetter (Eds.), Synthesis Gas Combustion. Fundamentals and Applications, 2010, Sec. 6.3 and Christopher Higman and Maarten van der Burgt, Gasification, 2nd Ed., Elsevier, 2008, Table 6.2.

particularly serious consequence for the TEC project, which for numerous reasons presents one of the better and more cost-effective opportunities in the nation to implement this technology.

Since CCS technology is clearly available, is planned at other IGCC sources, and has been determined to be feasible using nearby sequestration opportunities by Tenaska's *own analysis* (at an earlier time when political opportunities favored such a conclusion), IEPA was required to fully evaluate technical feasibility under Step 2. Had it done so, it would have properly concluded that CCS is, in fact, technically feasible for the Project, and would have been required to proceed to Step 4 to evaluate cost-effectiveness. When CCS is fairly evaluated, it becomes clear that it is both feasible and cost-effective for the Tenaska project and, therefore, must be required as BACT.

a. IEPA Improperly Eliminated CCS as Technically Infeasible in BACT Step 2

As explained in the Project Summary, the CO₂ vent of the AGR Unit would be the Facility's principle source of CO₂ emissions – amounting to 2,510,321 tpy generated from the gasification block and the production of SNG. While IEPA and Tenaska accept CCS as “available” for purposes of BACT Step 1 (as they must, according to USEPA's PSD and Permitting Guidance for Greenhouse Gases¹⁸⁰ (“U.S. EPA GHG BACT Guidance”)), they reject it under Step 2 based on “technical infeasibility.” *See* Project Summary at 31¹⁸¹; *see also id.* at 29-33. In addition to a number of inchoate references to general legal and financial concerns that do not constitute BACT Step 2 factors, IEPA relies on two primary technical concerns: (a) the unavailability of a CO₂ pipeline for EOR purposes, *id.* at 31, and (b) “many other technical issues associated with geologic CO₂ sequestration [in the Mt. Simon formation that] still need to be resolved,” *id.* at 32. However, for the reasons explained more specifically below, available information, including Tenaska's own statements in other contexts, clearly demonstrates that CCS is technically feasible, in contrast to the cursory and conclusory statements made by Tenaska and IEPA.

b. IEPA Failed to Conduct a Proper BACT Step 2 Analysis to Support its Conclusion that CCS Is Infeasible

The NSR Manual and opinions regarding top-down BACT by the EAB interpret BACT as requiring considerable specificity in a Step 2 feasibility evaluation. The NSR Manual requires that in Step 2, “A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.” NSR Manual at B-6. The Manual describes Step 2 as a two-part analysis of both whether the

¹⁸⁰ Available at <http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> and attached as Ex. 51. The U.S. EPA Guidance states at 32, “For the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is ‘available,’” and that “CCS should be listed in Step 1 of a top-down BACT analysis for GHGs.”

¹⁸¹ While IEPA does not walk through the steps in a top-down BACT analysis, its elimination of CCS as technically infeasible is consistent with a decision under BACT Step 2.

technology at issue is commercially available on any source, and whether, if so, it is applicable to the source type at issue:

Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

NSR Manual at B-17. The Manual further specifies that a technology is presumed to be applicable where it is "soon to be deployed" at a similar source type; but that even if it is not, the permitting authority must still make its own reasoned technical judgment as to applicability:

Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (*e.g.*, is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously.

Id. at B-17. In *In re Mississippi Lime*, the EAB rejected IEPA's Step 2 analysis as deficient, holding that IEPA had not sufficiently evaluated the feasibility of natural gas firing in the subject lime kiln. The decision noted, in particular, that reliance upon a natural gas pipeline cost estimate was not sufficient basis to eliminate the natural gas option under Step 2, but rather required that IEPA proceed to Step 4 in order to evaluate cost effectiveness:

IEPA's attempts to frame the use of natural gas as an "unresolvable technical difficulty" based on the proposed plant site's distance from the existing natural gas pipeline fail to recognize that "where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible." NSR Manual at B. 19. Because IEPA's "technical" difficulty is actually merely a matter of cost, IEPA has not shown that natural gas is technically infeasible... On this record, IEPA's consideration of natural gas as BACT should have included a step 4 BACT analysis. Instead, the entirety of IEPA's analysis prior to determining natural gas "not commercially feasible" was a single cost estimate for extending natural gas service to the proposed plant. *Mississippi Lime Additional Information* at 18. This cost estimate failed to consider the average and incremental cost-effectiveness of natural gas.

In re Mississippi Lime, slip op. at 7.

The U.S. EPA GHG BACT Guidance does allow for the possibility that, in the circumstances where there are “significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (*e.g.*, sources that emit CO₂ in amounts just over the relevant GHG thresholds and produce a low purity CO₂ stream) a much less detailed justification may be appropriate and acceptable for the source.” USEPA GHG BACT Guidance at 36. However, the Guidance makes clear that the applicability of this exception to the generally stringent analytical requirements of Step 2 is specifically limited to situations where sequestration opportunities are generally unavailable, *and* where CCS has never been used in the same source category:

In circumstances where CO₂ transportation and sequestration opportunities already exist in the area where the source is, or will be, located, or in circumstances where other sources in the same source category have applied CCS in practice, the project would clearly warrant a comprehensive consideration of CCS. In these cases, a fairly detailed case-specific analysis would likely be needed to dismiss CCS.

Id.

In this regard, we note that the “logistical hurdles” referenced in connection with this limited exception should not be read to generally conflate issues of cost properly considered under Step 4 with those of technical feasibility that are relevant to Step 2. U.S. EPA properly points out that for CCS, “as with all top-down BACT analyses, cost considerations should not be included in Step 2 of the analysis, but can be considered in Step 4.” *Id.* at 37. The U.S. EPA GHG BACT Guidance suggests that logistical factors relevant to a Step 2 analysis of CCS “may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage.” *Id.* at 36. But those factors could be relevant to Step 2 only to the extent that they make CCS technically infeasible. If, instead, these logistical factors would merely require the spending of additional resources to resolve, then those factors should be deferred to Step 4 because, as was explained in the 1990 Draft NSR Manual:

Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.

A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such

modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology

(NSR Manual at B.19 to B.20). And to the extent that these logistical hurdles may be considered at all in a Step 2 analysis at all, it is clear that they are intended only to apply to “smaller sources” – for example, “a small natural gas package boiler” (*id*) that may not have the “resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations.” *Id.* Clearly, the proposed Facility – a 630 MW generating station with a multi-billion dollar price tag¹⁸² – is not a “smaller” source.

Notwithstanding these clear requirements, IEPA presented no “detailed case specific analysis” of the technical feasibility of CCS in Step 2. As discussed in more detail below, it confined its evaluation to vague and largely unsupported references to purported technical and general non-technical hurdles to implementation. These generalized issues clearly do not constitute the detailed case-by-case technical evaluation of feasibility contemplated in Step 2, which requires for a showing of infeasibility a demonstration “based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.”¹⁸³ It is not sufficient for IEPA to simply regurgitate results of a broad general analysis of largely non-technical barriers to implementation of CCS in the United States as a basis to circumvent the requirement that it conduct detailed analysis and produce a well-reasoned and supported project-specific determination.

c. IEPA Erred in Its Analysis of Geologic Sequestration in Sandstone in the Mt. Simon Formation

Regarding geologic sequestration in the Mt. Simon formation, IEPA’s cursory “analysis” of Step 2 technical infeasibility acknowledges a “detailed feasibility study” done by CCG’s own consultant that had “favorable” results, but then vaguely relies on “many other technical issues associated with geologic CO₂ sequestration [that] still need to be resolved” and “unresolved issues involving the regulatory requirements for sequestration and liability associated with sequestration” to reject CCS. *See* Project Summary at 32. This discussion is wholly inadequate in terms of meeting the agency’s evidentiary burden, as well as wrong as a matter of technical substance.

In connection with the now-defunct Illinois Clean Coal Portfolio Standard legislation, under which Tenaska was required to demonstrate that the Facility would use CCS in order to qualify as the “initial clean coal facility” in Illinois, Tenaska in February 2010 submitted a Facility Cost Report¹⁸⁴ to the Illinois Commerce Commission, Illinois Power Agency, and the Illinois General Assembly in which the company explained its

strategy of pursuing the sale of its CO₂ for EOR through its contract with

¹⁸² Capital cost set forth in Facility Cost Report at 23.

¹⁸³ NSR Manual at B.6.

¹⁸⁴ Worley Parsons, Taylorville Energy Center – Facility Cost Report (Feb. 26, 2010), available at <http://www.icc.illinois.gov/electricity/tenaska.aspx>, attached as Ex. 52.

Denbury while also developing its own nearby storage field and seeking an injection.¹⁸⁵

Tenaska further noted that it “has developed a backup geologic storage strategy that it *will implement* if the Denbury pipeline is not completed in a timely manner.”¹⁸⁶ Having made clear in the context of seeking ratepayer subsidies for its proposed coal plant that it plans to sequester CO₂ emissions, Tenaska cannot now cursorily dismiss CCS as somehow not technically feasible.

Tenaska included with its Facility Cost Report twin reports developed by Schlumberger Carbon Services (“Schlumberger”) – including a Feasibility Study and a Cost Study – evaluating in significant detail the possibility of sequestration of captured CO₂ at the nearby Mt. Simon sandstone formation in Illinois.¹⁸⁷ That analysis considered all of the appropriate technical feasibility issues such as geologic suitability of the Mt. Simon site, injection well plume modeling, seismic data, *etc.*, and concluded that use of the site was entirely feasible for the Facility:

A geological study was completed to develop an assessment of the suitability of the site for storage of carbon dioxide. The work is the first phase in developing a geologic carbon dioxide (CO₂) storage site in the Mt. Simon formation. The goal of the study was to evaluate:

1. Whether the site has capacity to store the expected volume of CO₂ from the plant;
2. Containment of the storage reservoir;
3. Infrastructure requirements for storage (number and dimensions of injection wells, operational strategies)

The results of the study indicate that the Mt. Simon sandstone has sufficient porosity (open space between the sand grains in the rock) and permeability (the degree to which the pore spaces are interconnected, allowing fluid to move through the rocks) and therefore provides a storage reservoir target capable of accommodating all of the CO₂ produced by the plant over a planned operational life of 30 years. The Eau Claire formation, which overlies the Mt. Simon sandstone, will provide the vertical containment needed to prevent movement of CO₂ out of the Mt. Simon formation and into shallower geologic formations, ground water, and the atmosphere. There are also several other low permeability layers that provide secondary containment. The Mt. Simon formation and the containment layers are laterally extensive and available information, including

¹⁸⁵ *Id.* at 80-81.

¹⁸⁶ *Id.* at 77.

¹⁸⁷ See *Exhibit 13.2.a, Schlumberger Carbon Services Summary Results for Carbon Storage Feasibility Study* (“Schlumberger Feasibility Study,” attached as Ex. 53), and *Exhibit 13.2.b, Schlumberger Carbon Services Cost Report for the Taylorville Energy Center* (“Schlumberger Cost Study,” attached as Ex. 54, *cited at* Project Summary at 31 n. 29.

the results of a subsurface (seismic) survey, confirm that there are no faults or breaks in the lateral continuity¹⁸⁸

The Schlumberger Cost Study further concludes:

The geologic setting is favorable. The target formation of the Mt. Simon is estimated to be very thick at 1100-1300 feet with a high estimated porosity and permeability in the area selected. The thickness combined with the porosity and permeability allows for a high capacity injection field to be developed using a minimal number of wells. The field is estimated to only require 3 to 4 wells with a well spacing of only 2 miles. The thickness also reduces the area required for the CO₂ resulting in reduced right of way. Also, the target area is under and adjacent to the plant resulting in minimal pipeline cost.¹⁸⁹

None of this specific technical information was even referenced, much less considered, in the Project Summary rejection of CCS as technically infeasible.

The Project Summary also failed to take into consideration both existing CCS projects – including one in the immediate vicinity of the proposed site for the Taylorville Energy Center – demonstrating that the technology is technically available, and planned projects specifically employing CCS in the IGCC context to demonstrate applicability. The Project Summary makes essentially no mention of the CCS project operated by Archer Daniels Midland (“ADM”) in Decatur, Illinois which is making use of the Mt. Simon formation to sequester carbon from an ethanol manufacturing facility – a mere 30 miles from the proposed Tenaska site.^{190,191} The biggest source of technical uncertainty in any sequestration project is the suitability of the geology¹⁹², but that issue has already been addressed here. Not only does the Schlumberger Feasibility Study provide a clear preliminary evaluation of the geologic suitability of the site and a description of concrete steps, along with estimated costs, for establishing such suitability, but the practical experience and wealth of data that have already been obtained as part of the ADM Decatur project have filled many previous knowledge gaps and significantly decreased the complexity and cost of the remaining task for Tenaska. Now that the Midwest Geological Sequestration Consortium (“MGSC”) – with the help of ADM, Schlumberger and US DOE – has performed the characterization, IEPA should have used that knowledge in its analysis of technical feasibility (and, as discussed in the subsection below concerning Step 4, CCG could have used it to curtail its site characterization expenses). A good deal of operational knowledge

¹⁸⁸ Schlumberger Feasibility Study at 1

¹⁸⁹ Schlumberger Cost Study at 1.

¹⁹⁰ See MIT fact sheet concerning the ADM project *available at* <http://sequestration.mit.edu/tools/projects/decatur.html>, attached as Ex. 55.

¹⁹¹ See presentation by Robert J. Finley of the Midwest Geological Carbon Consortium on the Illinois Basin Decatur Project *available at* http://www.netl.doe.gov/publications/proceedings/11/carbon_storage/wednesday/RFinley_NETL_IBDP_Overview_Nov16.pdf, attached as Ex. 56.

¹⁹² See Interdisciplinary MIT Study on the Future of Coal, 2007, p. 43 et seq., *available at* http://web.mit.edu/coal/The_Future_of_Coal.pdf, attached as Ex. 57.

is gained when a well is drilled in a new formation, which should have been considered in the Tenaska BACT analysis. In the face of this wealth of information supporting sequestration nearby the site, IEPA's rejection of CCS by referencing "many other technical issues" justifying rejection of CCS falls far short of meeting the agency's BACT analysis obligation.

Furthermore, as to applicability (*i.e.*, whether a control option can reasonably be installed and operated on the source type under consideration), the Project Summary references but fails to evaluate three planned full-scale IGCC CCS projects being sponsored by USDOE. IEPA writes them off simply by noting that the Facility is not one of these projects. This cursory dismissal is unacceptable for purposes of Step 2 analysis. IEPA should be required, at minimum, to explain why, if at all, the proposed CCG project differs from the DOE projects so as to make CCS technically infeasible for Tenaska, given that USDOE has determined it to be fully feasible elsewhere (particularly in light of the availability of the nearby Mt. Simon formation). See NSR Manual at B.17.¹⁹³

Finally, IEPA erred in its reliance on Underground Injection Control ("UIC") program requirements in eliminating from consideration "carbon sequestration in the Mt. Simon formation or any other candidate geologic sequestration site."¹⁹⁴ IEPA cryptically cites "unresolved issues involving the regulatory requirements for sequestration and liability" in one sentence, followed by a second sentence setting forth that "[f]urther development of sequestration is needed" before BACT can be set based on CCS. This second sentence is accompanied by a footnote discussing U.S. EPA's UIC regulations for groundwater protection. The footnote asserts that the project might not be able to obtain a permit in a timely manner, or even if it could obtain a permit, it might not be possible to sequester CO₂ from the plant in the Mt. Simon formation under the UIC program. This discussion again fails to meet IEPA's evidentiary and substantive burdens. Because the UIC program presents no significant hurdle to CCS, it cannot be used as a justification for eliminating CCS in Step 2.

USEPA promulgated its Class VI rule for underground injection of CO₂ for geologic sequestration in December, 2010.¹⁹⁵ The Class VI rule provides a clear and well-defined regulatory path for a facility developer wishing to obtain a permit for CO₂ sequestration, and addresses the specific concerns identified by IEPA in the Project Summary. Specifically, as the Project Summary itself correctly describes (at 32, n. 35), "the rule sets minimum technical criteria for permitting, geologic site characterization, area of review and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, sealing of wells, post-injection site care, and site closure of such wells. These requirements are tailored to address the specific characteristics of CO₂ when it[i]s sequestered, including the large volume of material, the buoyancy and viscosity of CO₂, and its chemical properties, as compared

¹⁹³ "For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible."

¹⁹⁴ Project Summary at 32, n. 35

¹⁹⁵ 40 CFR 146

to materials previous addressed under the UIC program”. The fact that the rule sets clear financial responsibility requirements that owners and operators must carry, offering a wide variety of financial instruments that can be used, and that it also sets a default post-injection monitoring period of 50 years, which can be modified if a showing is made to the UIC Program Director, is in stark contrast to the Project Summary’s assertion (at 35) that “there are unresolved issues involving the regulatory requirements for sequestration and liability associated with sequestration”.

We note, in this regard, that the GHG BACT analysis provided by the applicant incorrectly states that the Class VI rule has not yet been promulgated, and complains, “Without clarity on what body has the appropriate regulatory authority to grant Class VI injection well approval, it is unclear when EPA will promulgate a final Class VI rule or whether CCG will be able to obtain an injection well permit in a timely manner, and even if a permit is obtained, whether CCG will be able to permanently sequester CO₂ produced by the AGR vent in the Mt. Simon formation under the proposed permit system.”¹⁹⁶ While IEPA corrects this statement in the Project Summary, it fails to correct and eliminate the incorrect conclusions that flow from it with respect to purported legal uncertainties surrounding CCS.

Tenaska has submitted an application for a UIC Class VI permit¹⁹⁷, and IEPA offers no reason or information to suggest that the permit cannot be granted. The results of Tenaska’s 2D geologic survey as reported in the permit application are favorable:

The Mount Simon Sandstone has been extensively developed for disposal and storage using Class I injection wells in Illinois and Indiana, and is the main deep saline candidate reservoir being targeted for CO₂ storage at this site. Three identified characteristics of the Mount Simon Sandstone, as determined by ISGS and the MGSC, make it very suitable for injection at Taylorville and the area near the proposed TEC #1 well:

- 1) The Mount Simon Sandstone is deep in the subsurface of the Illinois Basin and site 2D reflection seismic interpretation indicates it is laterally continuous in this area;
- 2) It is of sufficient thickness to be used for CO₂ storage;
- 3) Preliminary results of the MGSC project in Decatur suggest sufficient reservoir potential is present with porosity and permeability.

Class VI Permit Application at 37. The modeling results in the Application indicate that sequestration is feasible. And CCG’s monitoring plan indicates that CCG is successfully navigating the long-term management issues that IEPA vaguely argues may be insurmountable.

¹⁹⁶ Updated Prevention Of Significant Deterioration And State Construction Permit Application For The Taylorville Energy Center, Illinois Permit No. 05040027 Volume 3 Of 3 Greenhouse Gas Best Available Control Technology Analysis, at 6-9.

¹⁹⁷ Christian County Generation, LLC-Taylorville, Illinois Class VI Permit Request (September 20, 2011 (“Class VI Permit Application”), available at <http://www.epa.gov/r5water/uic/tec/pdfs/tec-permit-appl-2011-09.pdf>, attached as Ex58.

Moreover, the Class VI permit application submitted by ADM provides additional support for concluding that sequestration at Mt. Simon is feasible and a permit for it obtainable. According to the U.S. EPA Region 5, “ADM proposes to inject CO₂ from its agricultural products and biofuel production facility. The goal of the project is to demonstrate the ability of the Mt. Simon geologic formation to accept and retain industrial scale volumes of CO₂ for permanent geologic sequestration. The CO₂ will be injected more than 5000 ft below ground level. The project has a projected operational period of five years, during which time 4.75 million metric tons of CO₂ will be injected. Following the operational period, ADM proposes a post-injection monitoring and site closure period of ten years. EPA received ADM’s application for a permit for one CO₂ injection well in July 2011. It was assigned the identification number IL-115-6A-0001. U.S. EPA is reviewing the application for technical adequacy. (November 2011)”¹⁹⁸ Clearly, there is no basis for a categorical assumption that permitting the needed injection wells in the Mt. Simon would not be possible.

d. IEPA Erred in Its Analysis of Pipeline Resources for EOR

IEPA’s determination that sequestration is infeasible due to lack of EOR opportunities also is in error. The Project Summary writes off the possibility of EOR in connection with the project by stating that “[t]here currently is not a market for CO₂ from the proposed plant for EOR since CO₂ is not used in Illinois for EOR”; that “existing EOR practices cannot produce higher oil recovery rates in an economical manner”; and that “Illinois oil producers have no experience with conducting EOR at oil fields in the Illinois Basin” (Project Summary at 31). The Project Summary additionally makes no reference to other EOR opportunities in the Midwest outside of Illinois, referencing only a CO₂ pipeline that exists in connection with EOR operations in Mississippi. *Id.* These statements and omissions present a woefully inadequate characterization of EOR opportunities in Illinois and the Midwest region, and thus an impermissibly incomplete record for rejecting CCS. The real picture presents many opportunities not evaluated by IEPA, supporting that sequestration associated with EOR is feasible for the project.

A report prepared in 2006 by Advanced Resources International for USDOE (“ARI DOE Report”)¹⁹⁹ states categorically that

Illinois and Michigan Basin oil producers are familiar with using technology for improving oil recovery. For example, producers have used waterflooding in the Illinois basin since the 1950’s to improve oil recovery. More recently, two small CO₂-EOR projects have been ongoing for nearly 10 years in Michigan.

ARI-DOE Report at 3-3. A report prepared in 2009 by Advanced Resources International for USDOE (2009 ARI DOE Report)²⁰⁰ as an update to the 2006 ARI-DOE Report estimated that

¹⁹⁸ U.S. EPA Region 5 at <http://www.epa.gov/r5water/uic/adm/index.htm> (December 2011)

¹⁹⁹ Advanced Resources International, 2006, *Basin Oriented Strategies for CO₂ Enhanced Oil Recovery: Illinois & Michigan Basins*, prepared for U.S. Department of Energy, Office of Fossil Energy – Office of Oil and Natural Gas, 104 p, available at [http://www.adv-res.com/pdf/Basin%20Oriented%20Strategies%20-%20Illinois Michigan Basin.pdf](http://www.adv-res.com/pdf/Basin%20Oriented%20Strategies%20-%20Illinois%20Michigan%20Basin.pdf) (attached as Ex. 59).

²⁰⁰ Advanced Resources International, 2009, *Storing CO₂ and Producing Domestic Crude Oil with Next Generation CO₂-EOR Technology*, prepared for U.S. Department of Energy, National Energy Technology Laboratory,

the economically feasible market for CO₂ for use in CO₂-EOR in the Illinois and Michigan Basins could be up to 421 million metric tons, assuming an oil price of \$100/barrel and CO₂ costs of \$60/metric ton.²⁰¹

The Project Summary statement that “existing” EOR practices cannot function economically in Illinois is particularly misleading in light of the fact that the ARI-DOE reports expressly distinguish between “traditional practices” technology, “state of the art”/“best practices” technology, and “next generation” technology for EOR, and discuss in detail the fact that state-of-the-art and next generation technology would render EOR more economical than traditional practices technology – which is defined as “...use of *past* CO₂ flooding and reservoir selection practices.”²⁰² Specifically, the 2006 ARI-DOE report found that using “state-of-the-art” EOR practices would allow 500 million barrels of stranded oil to be recovered, even at \$1.50 per Mcf CO₂ and \$30/bbl oil prices. Oil prices equal to \$40/bbl would allow 600 million barrels of stranded oil to be recovered. With an oil price of \$40/bbl, CO₂ cost of \$0.80/Mcf, and 15 percent rate of return hurdle, 630 million barrels of stranded oil could be economically recovered.

The 2009 ARI-DOE report estimated that the technically recoverable resources from applying “best practices” technology in the Illinois and Michigan Basins is 1.2 billion barrels and applying “next generation” technology is 3.2 billion barrels.²⁰³ The report estimated that the economically recoverable resources from applying “next generation” technology would be 1.7 billion barrels using a base case of \$70/barrel oil and \$45/metric ton CO₂, delivered at pressure to the field.²⁰⁴ A report prepared in 2010 by ARI for the Natural Resources Defense Council (2010 ARI-NRDC Report)²⁰⁵ estimated that the economically recoverable resources from applying “best practices” technology would be 0.5 billion barrels and from applying “next generation” technology would be 1.7 billion barrels, assuming \$70/bbl oil and \$15/metric ton CO₂.²⁰⁶ Using an oil price of \$100/barrel – the approximate value at which oil is trading today – the 2009 ARI-DOE report estimated that 2.1 billion barrels could be economically recovered.²⁰⁷

Other studies of EOR opportunities in the Midwest have reached similarly optimistic conclusions concerning the availability of EOR opportunities in Illinois and surrounding states. A 2009 report prepared by Kinder Morgan for the State of Illinois’ Department of Commerce

74p.<http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20Next%20Generation%20CO2-EOR.pdf> (attached as Ex. 60).

²⁰¹ 2009 ARI-DOE Report at 53.

²⁰² 2006 ARI-DOE Report at 5-10 *et seq.*, 2009 ARI-DOE report at 30 *et seq.* (emphasis added),.

²⁰³ 2009 ARI-DOE Report at 42.

²⁰⁴ 2009 ARI-DOE Report at 46.

²⁰⁵ Advanced Resources International, 2010, U.S. *Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage*, prepared for Natural Resources Defense Council, 56p., available at <http://www.adv-res.com/pdf/v4ARI%20CCS-CO2-EOR%20whitepaper%20FINAL%204-2-10.pdf>, attached as Ex. 61.

²⁰⁶ 2010 ARI-NRDC Report at 11.

²⁰⁷ 2009 ARI-DOE Report at 48.

and Economic Opportunity (Project Lincoln)²⁰⁸ determined that in Illinois alone 300 million barrels of oil could be recovered using CO₂-EOR. The report concludes that initially just over 80 million cubic feet per day (“MMcfd”) of CO₂ would be required on average, growing to almost 350 MMcfd. And an additional study by ARI for the Midwestern Governors Association²⁰⁹ found that 175 reservoirs in 8 of the 12 states represented by the MGA have CO₂-EOR potential, with a technically recoverable resource up to 7.5 billion barrels. Illinois and Kansas combined have the largest resource potential, up to 4 billion barrels. Using a base case of \$70/bbl oil and \$45/metric ton CO₂, the Midwestern region could produce up to 3.9 billion barrels of oil using 830 million metric tons of CO₂. While transportation issues would need to be addressed in assessing the commercial viability of these opportunities, as noted above, general references to the need to construct a pipeline are insufficient basis for failing to conduct complete Step 2 analysis – particularly where, as here, there is strong evidence that pipeline construction would be affordable (see subsection below).

e. IEPA Failed to Explain Why Various Legal and Financial Questions Rise to the Level of “Logistical Hurdles” for the Project under Step 2’s Technical Feasibility Inquiry

As noted above in subsection b., in addition to its presentation of purported technical issues concerning Mt. Simon and EOR, IEPA makes even more vague references to the need for legal/regulatory frameworks for CCS, market failures related to climate policy, questions of long-term liability and public information campaigns in its discussion of CCS. See Project Summary at 30-31, 32.²¹⁰ It is unclear in the Project Summary the extent to which IEPA relied on or gave weight to these factors in its determination of Step 2 technical infeasibility, but any such reliance was both factually unsupported and legally impermissible. Non-technical factors – particularly where they are grounded in factual error or are not shown to be applicable – are neither cognizable nor appropriate in a BACT Step 2 analysis.

As discussed in subsection b., to the extent that these concerns are related to the UIC program, they are generally invalid from a factual standpoint as they have for the most part been fully addressed in EPA’s Class VI rulemaking. Additionally, IEPA has failed to explain the relevance of the very general non-technical factors to the specific project at hand. It has also

²⁰⁸ <http://www.commerce.state.il.us/NR/rdonlyres/4FE157DB-C1F7-4F2B-B46B-5F718A08E881/0/IllinoisCO2PipelineReport20090715.pdf>, attached as Ex. 62.

²⁰⁹ Ferguson, R., Advanced Resources International, 2009, *CO₂-Enhanced Oil Recovery Potential for the MGA Region*, prepared for Midwestern Governors Association, 30p, available at <http://www.midwesterngovernors.org/Energy/CO2EORpotential.pdf>, attached as Ex 63.

²¹⁰ IEPA generally referenced the following as supposed hurdles to implementation of CCS:

- (1) The Facility is not one of the three United States Department of Energy (“USDOE”) IGCC demonstration projects (Project Summary at 30).
- (2) The federal Interagency Task Force August 2010 report identified four “near-term and long-term concerns for the full-scale commercial application of CCS,” including (i) the lack of climate policy to set a price on carbon and encourage emission reductions, (ii) the need for a “legal/regulatory framework” that facilitates reject development and “provides public confidence” in CCS; (iii) clarity with respect to long-term liability for sequestration and (iv) the need for “integration of public information, education, and outreach throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.” (*Id.*)

failed, as noted above, to explain why the existence of three full-scale IGCC projects (Project Summary at 30) weighs *against* requiring CCS at the TEC rather than in favor of it. IEPA has also not provided any reason why general purported “market failures” regarding carbon would affect the *technical* feasibility of CCS *at this plant*. The Agency has likewise failed to explain how and why the lack of full legal and regulatory frameworks for CCS projects in general (at best a severe exaggeration of current circumstances given the new Class VI permitting regulations discussed above) would stand in the way, as a *technical* matter, of creating permit terms and conditions that protect human health and the environment and that provide for long-term liability for sequestration (particularly when the Class VI Permit Application contemplates exactly such terms). The agency merely throws out a general laundry list that is almost entirely irrelevant to the case-by-case technical assessment required by BACT.

f. IEPA Failed to Demonstrate that Overwhelming Hurdles Justify the Omission of a Detailed, Case-by-case BACT Analysis

For all of the reasons discussed above, IEPA has not even come close to demonstrating that it may avail itself of the very narrow allowance in the USEPA guidance for a more limited Step 2 analysis in circumstances where “significant and overwhelming technical (including logistical) issues associated with the application of CCS” allow for a “less detailed justification” of the technical feasibility of CCS in Step 2.²¹¹ In the first instance, as discussed above, “CO₂ transportation and sequestration opportunities already exist in the area where the source is” – in the form of the ADM project and the Mt. Simon formation – thus clearly warranting a “detailed case-specific analysis” before dismissing CCS as infeasible pursuant to the USEPA Guidance. In this regard, we note that the need for, at most, a very short (approximately 30 mile, as discussed below) pipeline is insufficient basis to simply wave away the possibility of CCS at the Facility, in view of both the *In re Mississippi Lime* decision that the need to construct a pipeline is not a *per se* demonstration of infeasibility, and the data presented in the subsection below indicating that the cost of a pipeline would be far from prohibitive. Additionally, we note that the proposed Facility falls into neither category of examples provided in the USEPA Guidance describing types of facilities for which less thorough Step 2 analysis would likely be necessary – “sources that emit CO₂ in amounts just over the relevant GHG thresholds and produce a low purity CO₂ stream.” The Facility would produce a very high purity CO₂ stream at the AGR Unit vent²¹², and would generate a total of 5,031,423 tpy of CO₂e, well above the applicable threshold of 75,000 tpy necessary in order for the Tailoring Rule to apply.²¹³

Faced with a project applicant that informed the Illinois General Assembly and others that it would sequester CO₂ emissions, IEPA has blindly accepted contradictory statements from the applicant that CCS is not technically feasible without even acknowledging, much less attempting to address, this inconsistency. In short, IEPA has wholly failed to either evaluate the technical feasibility of CCS pursuant to Step 2, or to demonstrate why thorough case-specific

²¹¹ USEPA GHG BACT Guidance at 36.

²¹² “[...] the gases exhausted from the AGR vent stream are primarily CO₂”. Updated Prevention of Significant Deterioration and State Construction Permit Application for the Taylorville Energy Center, Illinois Permit No. 05040027 Volume 3 Of 3 Greenhouse Gas Best Available Control Technology Analysis, at 6-1.

²¹³ *Id.* at 3-4.

analysis of feasibility was unnecessary. Had it conducted a proper analysis, the Agency would have been compelled to conclude that CCS is, indeed, technically feasible for the Project, just as CCG's own consultant Schlumberger concluded earlier. Because, as described below, CCS is also cost-effective for purposes of BACT, the IEPA must establish enforceable emission limits in any final permit for the CCG facility that reflect the capture and sequestration of 90% of the CO₂ from the vent for the AGR unit. At a minimum, IEPA must perform a proper analysis of the technical feasibility of CCS, with respect to both the Mt. Simon formation and EOR opportunities, and re-notice the permit in draft to allow for public comment on the more complete analysis.

2. CCS is Cost-Effective Pursuant to BACT Step 4

As discussed in *Mississippi Lime Company*, issues of cost associated with control technologies are required to be addressed in Step 4 of top-down BACT analysis rather than Step 2. IEPA does not directly reference cost at all in its evaluation of CCS in the Project Summary. However, it implies that the cost of pipeline construction would be prohibitive, since the only pipeline option it chose to evaluate was construction of a pipeline by a third party at its own expense. See Project Summary at 31. Had IEPA performed a Step 4 analysis, however, it would have determined both that CCS is cost effective in terms of the costs of capture, transportation and sequestration per ton of CO₂ for purposes of Step 4.

As discussed in the Project Summary, the capture of CO₂ "is inherent in coal gasification for production of SNG" (Project Summary at 29, n.23), which means that Tenaska's proposed production of SNG will create a high purity stream of CO₂ at the gasifier block as part of normal operations, *i.e.*, whether or not the project must sequester the carbon it produces. As such, the cost of capturing CO₂ need not and should not be counted as part of the cost of doing CCS at the CCG Facility. This, in and of itself, goes a long way toward making CCS cost effective for the Facility, since the bulk of the cost of any given CCS project of this kind lies in the capture of CO₂ rather than its transportation or sequestration. The 2005 *IPCC Special Report on Carbon Dioxide Capture and Storage*²¹⁴ summarized costs associated with CCS as follows:

²¹⁴ http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf , attached as Ex. 64.

Table TS.9. 2002 Cost ranges for the components of a CCS system as applied to a given type of power plant or industrial source. The costs of the separate components cannot simply be summed to calculate the costs of the whole CCS system in US\$/CO₂ avoided. All numbers are representative of the costs for large-scale, new installations, with natural gas prices assumed to be 2.8-4.4 US\$ GJ⁻¹ and coal prices 1-1.5 US\$ GJ⁻¹.

CCS system components	Cost range	Remarks
Capture from a coal- or gas-fired power plant	15-75 US\$/tCO ₂ net captured	Net costs of captured CO ₂ , compared to the same plant without capture.
Capture from hydrogen and ammonia production or gas processing	5-55 US\$/tCO ₂ net captured	Applies to high-purity sources requiring simple drying and compression.
Capture from other industrial sources	25-115 US\$/tCO ₂ net captured	Range reflects use of a number of different technologies and fuels.
Transportation	1-8 US\$/tCO ₂ transported	Per 250 km pipeline or shipping for mass flow rates of 5 (high end) to 40 (low end) MtCO ₂ yr ⁻¹ .
Geological storage ^a	0.5-8 US\$/tCO ₂ net injected	Excluding potential revenues from EOR or ECBM.
Geological storage: monitoring and verification	0.1-0.3 US\$/tCO ₂ injected	This covers pre-injection, injection, and post-injection monitoring, and depends on the regulatory requirements.
Ocean storage	5-30 US\$/tCO ₂ net injected	Including offshore transportation of 100-500 km, excluding monitoring and verification.
Mineral carbonation	50-100 US\$/tCO ₂ net mineralized	Range for the best case studied. Includes additional energy use for carbonation.

^a Over the long term, there may be additional costs for remediation and liabilities.

Other authors go as far as simply ignoring the cost of transport and storage entirely as being negligible compared to capture costs.²¹⁵

This relatively low cost of transport and storage is in line with the findings of the Schlumberger Cost Study with respect to the proposed Facility, which states only very modest costs for sequestration. That Study found that the cost of sequestration comes in at a total of \$116,717,679 for the lifetime of the project. This is small compared to the total capital costs for the plant that are on the order of several billion dollars. In addition, the Study found the cost of sequestration for the Facility to be significantly lower than the typical CCS cost range of \$5 to \$10 per metric ton of stored CO₂ given the very favorable geology of nearby Mt. Simon:

Based on Schlumberger Carbon Services evaluation and understanding of project requirements, including pending regulations, costs for typical carbon storage projects are likely to be in the range of \$5.00 to \$10.00 per tonne of stored CO₂. The project costs presented herein are lower than this range due to the very favorable geologic setting, the assumptions concerning project requirements, and other conditions for CO₂ injection specific to the Taylorville Energy Center (TEC). This project and cost report should not be considered representative or typical of other CO₂ storage projects.

Schlumberger Cost Study at 1.

²¹⁵ M. Al-Juaied and A. Whitmore, *Realistic Costs of Carbon Capture* (Discussion Paper July, 2009) at 8, available at http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf , attached as Ex. 65.

There are two additional reasons why sequestration costs might be even lower for CCG than those estimated by Schlumberger. First, significant and valuable site characterization has already been performed as part of the ADM Decatur project. If CCG were to use the Mt. Simon as a sequestration option, site characterization costs would be reduced as data is already available and an assessment without prior knowledge, as Schlumberger assumes in its cost estimates, would likely not be necessary. Second, the largest cost component is the proposed 4D seismic monitoring, at \$33,034,500. Although this technique has been used successfully in other projects, it is not mandatory according to EPA regulations, nor is it essential everywhere for proving the effectiveness of sequestration. It could be replaced with other techniques that are less costly – 4D seismic is one of, if not the most expensive, all the monitoring techniques available today.²¹⁶

Outside of capture and sequestration costs, the other potentially significant costs associated with CCS at the Facility are those of compression and pipeline transportation. We were not able to identify the costs associated with compression only for CCS at the Facility from the permitting or other publicly available documents. We note that the “capture” costs reported by the IPCC above include the costs of compression, and that the costs of capture and compression together for this Facility likely will be consistent with the ranges in the IPCC report. It should be noted that the gasification and methanation process produce CO₂ at high pressure, thereby reducing any potential compression costs for CCS.²¹⁷ A short pipeline, which is a key option for the plant, would also decrease the need for compression. In any case, Tenaska has not provided any data on potential compression costs and no credible argument has been put forward that such costs would be significant or that compression might render CCS at the plant non cost-effective.

As far as pipeline transport is concerned, available data indicate that this cost as well is not a significant barrier. The Schlumberger Cost Study sets the cost of a pipeline to Mt. Simon as ranging from approximately \$4.3 to \$7.1 million, with the high figure being based on a conservative case for the number of injection wells that may be required. From all indications, at most a very short pipeline is all that is needed in order for the Taylorville Energy Center to sequester its captured CO₂. The Schlumberger Cost Report assumes this to be the case, stating, “the target area is under and adjacent to the plant resulting in minimal pipeline cost.”

²¹⁶ Other possible geophysical methods are referenced at http://www.netl.doe.gov/technologies/carbon_seq/corerd/mva.html and http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf

²¹⁷ The Class VI Permit Application at 95 explains as follows:

4.14.5 Injection Pump(s) The CO₂ will be compressed within the power plant and delivered to the injection well field under pressure. No injection well pumps will be required to deliver the captured CO₂ to the injection wells due to the fact that high pressure exists from the capture and compression process that will drive the CO₂ to the injection wells. The CO₂ will be compressed using two 50% capacity 8 stage integrally geared centrifugal compressors. Each compressor will be driven by an approximately 19,500 horsepower electric motor. The compressors will be equipped with intercoolers and after coolers to prevent excessive discharge temperatures. Flows and pressures will be controlled by inlet guide vanes using suction and discharge pressures as control points. In the event the inlet guide vanes are at the maximum travel distance, the system will recycle or vent CO₂ to prevent an over or under pressure situation. The compressor will have an emergency shutdown system. In the event a line leak or overpressure situation is detected, the emergency shutdown system will be activated to shut off flow of CO₂ to the pipeline.

Schlumberger Cost Report at 1. Additionally, in its February 2010 Facility Cost Report,²¹⁸ Tenaska noted that if the Denbury pipeline EOR approach to dealing with the CO₂ emissions from the Facility were not available, the company would “proceed with its backup plan to construct its own storage field under and just north of the TEC Site.”²¹⁹ Tenaska could therefore plausibly drill injection wells in the immediate vicinity of the plant. None of these facts are discussed in the Project Summary, however, nor are cost estimates for a plausible pipeline path presented in the Summary or the BACT Analysis by Tenaska.²²⁰

In fact, when CCS costs are calculated in terms of cost per ton of CO₂ sequestered, as is appropriate in Step 4, CCS at the Facility appears eminently cost effective. Although the Schlumberger Cost Study does not calculate a cost per ton for CCS at the Facility, as noted above, it concludes that such cost is lower than the \$5.00 to \$10.00 cost per ton range for a “typical” CCS project due to the favorable geologic setting. We used the cost information provided in the Schlumberger Cost Report to prepare a conventional BACT cost effectiveness analysis, using the EPA Air Pollution Control Cost Manual, 6th Ed., January 2002. It is unclear whether the Schlumberger Report includes the cost of compression. Thus, to be conservative, we estimated it, assuming two 50% capacity 8-stage integrally geared centrifugal compressors driven by 19,500 hp electric motors and a busbar electricity cost of \$50/MWh. Our analysis, included in Exhibit 137, indicates the cost effectiveness of capturing and transporting the CO₂ is \$8.82/ton. Actual cost effectiveness would be lower if the Schlumberger data already include compression costs or if credit were taken for selling the recovered CO₂. As Tenaska itself states in the Facility Cost Report,²²¹ the costs of carbon storage can be offset by EOR revenues where available.²²² We note, in addition, the Applicant’s observation in the Facility Cost Report that CCS costs would be further offset by “an increase in the applicable tax credit from \$10 to \$20/MT under Internal Revenue Code Section 45Q and a reduction in CO₂ compression

²¹⁸ *Taylorville Energy Center Facility Cost Report* (February 26,2010) (“Facility Cost Report”), Available at <http://www.icc.illinois.gov/downloads/public/en/ Taylorville%20Energy%20Center%20Facility%20Cost%20Report%20FINAL%20022610.pdf> , attached as Ex. 67.

²¹⁹ Facility Cost Report at 80.

²²⁰ We note, in this regard, that a 2010 report by the Interstate Oil and Gas Compact Commission-Southern States Energy Board found the upper-bound cost of pipeline construction – represented by the Green Pipeline in Louisiana, which was required to cross through sensitive wetlands – was \$93,750/in. diameter/mile. See IOGCC-SSEB, *A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide* 2010, (“IOGCC-SSEB”) available at <http://www.sseb.org/downloads/pipeline.pdf> , attached as Ex. 68. To be extremely conservative we could further assume, for argument’s sake that CCG were to construct a pipeline to the existing ADM CO₂ injection well that is approximately 30 miles away. According to IOGCC-SSEB, the needed diameter of the pipeline in order to transport the 2,510,321 tpy of CO₂ captured is between 8-12’’. Assuming the larger end of the range (12’’), which could accommodate up to 3,250,000 tpy of CO₂, and using the upper bound of the cost cited above at \$93,750/in. diameter/mile, the total cost would be \$33.7 million – an amount which is perfectly within the realm of the reasonable for a facility like this. Using the cost effectiveness formula set forth *infra*, pipeline of this nature would raise the cost per ton of CCS to \$1.71 per metric ton.

²²¹ *Id.* at 59,

²²² Massachusetts Institute of Technology, *Future of Coal in a Carbon Constrained World* 2007 at 58-59, available at <http://web.mit.edu/coal/>, attached as Ex. 69 (“MIT”).

requirements to 1,900 pounds per square inch after approximately the first five years of injection.”²²³

Although there currently is no generally agreed cost threshold for CO₂ BACT cost effectiveness, as discussed above, the cost of CCS at the Facility is at the very low end of the \$3-\$150/ton range referenced in Tenaska’s GHG BACT analysis (based in turn on the Clean Air Act Advisory Committee (“CAAAC”) Climate Change Workgroup Phase I Report). Application v.3 at 6-34. By the same token, it will likely be below even the current severely depressed price of carbon credits on the European market (approximately \$10 per tonne in December 2011).²²⁴ This figure is not, of course, an appropriate benchmark for BACT cost effectiveness, but rather represents a low-bound estimate of the value of carbon reduction on the open market in a recession economy. In the BACT context, given that the structure and purpose of the CAA requires that source developers shoulder a reasonable cost for implementing the best technology, above and beyond what the market would compel, Tenaska should be assumed capable and responsible to pay significantly more than that for purposes of a Step 4 cost effectiveness determination.

E. BACT WAS NOT REQUIRED FOR THE PRESSURE RELIEF VALVES

The TEC would include 126 pressure relief valves (“PRVs”), which are generally listed with equipment leak component.²²⁵ All of these PRVs except for 11 in GHG-service are routed to the flare.

The Application does not contain a BACT analyses for these PRVs, in either the flare BACT analysis or equipment leak BACT analysis. In the equipment leak section, the Application states only that the top technology for control of emissions from PRVs is routing them to an add-on control device, such as an oxidizer or flare.²²⁶ This is simply stated with no support or analysis. Other options were not considered and rejected.

First, the seals on PRVs can leak continuously, sending large constant volumes of gases to the flare. Rupture disks are used to prevent this leakage. Rupture disks are an extra metal seal that prevents leakage through the PRV until it opens. These were not considered in the BACT analysis and are not required by the Permit.

Second, PRVs are designed to open when the pressure gets above a certain set point in a vessel. When set point is exceeded, the disk ruptures, and the pressure relief valve opens. When the pressure relief valve later closes after the pressure goes back down, the rupture disk is no longer there, and it no longer provides any protection from leakage. Further, it is known that sometimes PRVs do not re-seat after opening properly, so leakage can occur through the PRV

²²³ Facility Cost Report at 81.

²²⁴ See <http://www.pointcarbon.com/> (last accessed December 28, 2011) (providing daily carbon credit market reports).

²²⁵ Ap., v. 1, Tables C-24 to C-27 and v. 3, Tables A-15 to A-19.

²²⁶ See, e.g., Ap., v. 1, p. 6-42, 6-51. and Draft Permit, Condition 4.9.2.c

seals. This requires a work practice standard, the immediate replacement of rupture disks after a flare event. This was also not considered in the BACT analysis or required in the Draft Permit.

Third, the BACT analysis is silent on control options for the 11 PRVs that are not routed to the flare. No control options at all are advanced. These PRVs should be routed to the AGR vent and subject to BACT level controls there.

Finally, the emission inventory does not include any emissions for PRV releases, except those from the 11 PRVs that are not vented to the flare. This essentially assumes that flaring controls 100% of the PRV emissions. The Application should have applied, at best, 98% destruction efficiency, for the times that leakage occurs. The Application should have included an evaluation employing a factor for how often rupture disks open, how fast they get repaired after opening, and included a Permit provision to guarantee these assumptions. And, these emissions should have been included in the Potential to Emit.

The attached document, *Flare Loss Monitoring*, is an example of an industry website that found that small leaks in PRVs routed to flares can cause large annual emissions.²²⁷ The diagram provided shows over 63,000 kg/year (or about 140,000 lbs/year) of leakage to the flare (before combustion) from a single PRV, and talks in general about substantial leakage to flares from PRVs. This document found that although the number of leaks should be small, the individual leak rate can be extremely large, and continuous. This document states:

Flare emissions to the atmosphere are losses of VOC's caused by internal leaking equipment such as pressure relief valves, ball- & gate valves. These uncontrolled emissions can lead to huge losses. The visible flame at the flare stack, the losses of raw materials, unreliable stream balances and the environmental aspect have created awareness that companies and organizations should work on their Flare emission monitoring programs. By the absence of a thorough monitoring and maintenance program, these emissions are the most significant cause of losses of raw materials resulting from plant activities.²²⁸

The AP-42 for industrial flares also recognizes that pollutants can be routed to the flare from leaking PRVs:

At many locations, flares normally used to dispose of low-volume continuous emissions are designed to handle large quantities of waste gases that may be intermittently generated during plant emergencies. Flare gas volumes can vary from a few cubic meters per hour during regular operations up to several thousand cubic meters per hour during major upsets. Flow rates at a refinery could be from 45 to 90 kilograms per hour (kg/hr) (100 - 200 pounds per hour [lb/hr]) for relief valve leakage but could reach a full plant emergency rate of 700 megagrams per hour (Mg/hr) (750 tons/hr).²²⁹

²²⁷ The Sniffers NV/SA, *Flare Loss Monitoring*, available at <http://www.the-sniffers.be/flare/monitoring.htm>, attached as Ex. 71.

²²⁸ *Flare Loss Monitoring* (Ex. 71).

²²⁹ AP-42 – Chapter 13.5-2, *Industrial Flares* (Sept. 1991) at 2-3.

Although the AP-42 refers to oil refineries, the pressure relief valves and their connection to the flare are exactly the same as the types used for Taylorville. These leakages can result in large emissions over time. In the refinery example provided by AP-42, 100-200 lbs/hour amounts to almost 440 to 880 tons per year routed to the flare ($100-200 \times 8,760$ hours in a year / 2,000 lbs/ton), which even at 98% efficiency would result in about 9 to 18 tons per year in added flare emissions. With 115 PRV routed to the flare, this source should have been subject to a rigorous BACT analysis and the emissions included in the emission inventory and air quality modeling.

F. BACT WAS NOT REQUIRED FOR THE FLARE

During normal operation of the gasification block, the only emissions from the gasification block would be from the natural gas fired pilot in the flare, exhaust from the SRU thermal oxidizer and incidental operations, such as storage and handling of sulfur. However, during non-normal conditions, such as startups, shutdowns, and malfunctions, raw and partially treated gases would be vented to the flare.

1. Clean Fuels

One major flaw in the BACT analyses is that IEPA failed to evaluate or require the use of cleaner fuels, such as lower sulfur coal or biomass, to reduce emissions of SO₂ and other pollutants during flaring. This use is distinguishable from the use of clean fuels as the feed to the gasifier, discussed in Section III.B above. Similar gasification projects routinely specify the use of low sulfur coal during planned startup and shutdown events.²³⁰ The BACT analysis for Taylorville concluded that the use of low sulfur subbituminous coal is not a technically feasible control option for reducing SO₂ emissions from the flare. The BACT analysis argues that the gasifiers and syngas gas conditioning train are specifically designed for the moisture content, ash content, and heating value of Illinois bituminous coal and the flow rate and composition of syngas the gasifiers produce using this feedstock.²³¹ However, none of these parameters are reported anywhere in the record or required as permit conditions.

This is incorrect as a technical matter. First, Siemens literature indicates that the subject gasifiers can burn a wide range of feedstocks.²³² Second, the majority of the emissions occur during the period when the raw syngas is sent directly to the flare without any treatment. In other words, it bypasses the syngas gas conditioning train. Thus, the design basis of this train is irrelevant. Also, the design of the coal handling system is not a constraint in processing a different coal for the short periods of time involved during planned startups and shutdowns. And any critical portion of the material handling system could have a parallel train designed for the alternate fuel. Thus, the BACT analysis must evaluate the use of low sulfur subbituminous and other low sulfur coals during non-routine operation.

²³⁰ See, e.g., West Virginia Department of Environmental Protection, Division of Air Quality, Permit to Construct, TransGas Development Systems, LLC, R13-2791, February 25, 2010, Cond. 4.1.5.5.c, p. 24 (“Coal gasified during start-up shall not contain sulfur in excess of 0.5% by-weight.”) (“TransGas Permit”), attached as Ex. 72.

²³¹ Ap., v. 1, p. 6-10.

²³² Siemens Fuel Gasifier; <http://www.energy.siemens.com/hq/en/power-generation/fuel-gasifier/>, attached as Ex. 73.

Further, even assuming design constraints during portions of non-routine events, we note that there is a wide range of similar Illinois Basin coals with lower sulfur than the design coal assumed in the emission calculations that have similar physical properties.²³³ The BACT analysis failed to consider other similar, lower sulfur Illinois Basin coals to reduce SO₂ emissions from flaring during startups, shutdowns, and malfunction. Other gasification projects routinely use a low sulfur coal pile to control non-routine flaring emissions.

As explained in Section III.B.1 above, the Clean Air Act requires that BACT limits be established based on the emission reductions achievable using cleaner fuels. 42 U.S.C. § 7479(3); 40 C.F.R. § 52.21(b)(12). The Application, IEPA Project Summary, and Draft Permit, however, all fail to include any evaluation of lower-sulfur coal as part of the BACT analyses for Taylorville. As such, the IEPA must require Tenaska to submit such an evaluation, and can allow Taylorville to avoid using lower sulfur coal only if Tenaska can demonstrate, and the IEPA can independently confirm, that the cost of pollutant removal from using such fuel is “disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations.”²³⁴

2. Flare Minimization

The Draft Permit requires operation according to detailed procedures to minimize emissions (Condition 4.1.5-1.e), flare minimization planning (Condition 4.1.5-3), and root cause analysis (Condition 4.1.5-3.d). However, these conditions do not actually require that flaring be minimized and do not satisfy BACT. Elements of an effective, enforceable flare minimization plan include those discussed below, which are missing from both the BACT analysis and the resulting Permit conditions.

Limits should be set on the amount of time equipment is permitted to operate during a malfunction. The BACT analysis did not discuss such limits and the Draft Permit does not establish any. Gasifiers are able to shut down in a matter of hours, and should be required to do so within a short period of time if they are the source of gas that is being flared. A permit issued to Power Holding requires shutdown within 3 hours of a malfunction that would cause emissions to be exceeded, unless the malfunction is expected to be repaired within 3 hours, or such shutdown could threaten the safety of personnel or equipment.²³⁵

Root cause analyses should be performed on all malfunctions or a certain subset thereof (*e.g.*, those releasing over a certain threshold of emissions). The Draft Permit limits eligible events to only those with higher emissions than a cold startup. Condition 4.1.5-3.d.²³⁶ A much

²³³ See, *e.g.*, USGS Report, *supra* n. 3.

²³⁴ NSR Manual, pp. B.31-B.32.

²³⁵ Power Holdings Permit, at 1-99.

²³⁶ Condition 4.1.5-3.d requires root cause analysis only for “flaring incidents.” A “flaring incident is defined as a flaring event that produces excess emissions above permit limits and accompanies the unscheduled shutdown of the gasification block or a malfunction of a process unit that results in process gas being routed to the flare.” The

larger subset of events should be subject to root cause analysis. The South Coast Air Quality Management District flare regulation requires root cause analysis for any flare event emitting greater than 500 lbs/day SO_x, but also for any flare event with greater than 100 lbs/day of VOCs.²³⁷ The Draft Permit would only require a root cause analysis if emissions were orders of magnitude higher.

The Permit should require that prior to being flared, process gas pass through as much of the syngas cleanup system as feasible, even during a malfunction. For instance, the recently re-issued permit for Southeast Idaho Energy requires upset gas to pass through the sour water scrubber, the activated carbon beds, and an amine scrubber to reduce the sulfur content prior to being flared.²³⁸

The BACT analysis and Permit should require a preventative/predictive maintenance plan. Some malfunctions are the result of insufficient maintenance and could be prevented with a routine schedule of preventative maintenance (rather than waiting until something is broken). A predictive maintenance plan monitors certain parameters and helps to anticipate where maintenance is most likely to be needed.

The BACT analysis and Permit should require evaluation and procurement of backups for key pieces of equipment (optimization of redundancy where appropriate). For example, Eastman's Kingsport gasification facility has significantly decreased its forced outage rate through detailed reliability and redundancy modeling. The Application and Draft Permit are silent as to redundancy.

The BACT analysis and Permit should require a flare monitoring plan detailing the monitoring equipment discussed below and operating procedures for the monitoring equipment, provided in advance of approval of the project. Without accurate feedback about flare emissions, flare minimization planning is not effective. Without rigorous monitoring, flaring events can go undetected, unreported, or underestimated. A root cause analysis requirement would not be triggered for events that go undetected.

The Power Holdings Flare Minimization Plan, for example, is detailed and lengthy. All of these detailed requirements in the Power Holdings flare minimization plan set the BACT standard and must be required for Taylorville. These include the requirements for procedures for preventative maintenance; procedures for periodic evaluation of flaring activity generally and specific evaluation of flaring incidents; and an evaluation of preventative measures to reduce the occurrence and magnitude of flaring for the gasification block.

subject permit limits at Condition 4.1.6.b are the limits for a cold startup. Thus, many lesser, though still very large malfunctions could occur repeatedly without triggering a root cause analysis. Further, the Draft Permit does not contain sufficient monitoring to determine when these limits are exceeded. *See* Comment --.

²³⁷ SCAQMD Rule 1118 at 1118-5.

²³⁸ Southeast Idaho Energy Permit.

3. Alternative Flare Technology

The Taylorville flare is currently designed as an elevated flare. Flare exposure to wind significantly reduces combustion efficiencies. In addition, direct monitoring of an elevated flare is not as feasible as with a ground flare. This could be remedied by the use of an enclosed ground flare for the expected periodic events associated with gasifier startup. The Application eliminated a ground flare as not an available control option due to noise, heat, and other objectionable attributes.²³⁹ However, no support is provided for these speculations. Further, they are inconsistent with experience elsewhere.

The Bay Area Air Quality Management District (“BAAQMD”) in California, where five large petroleum refineries are located, identifies use of an enclosed ground flare as BACT for flare emissions. The BAAQMD also assigns an assumed VOC destruction efficiency of 98.5% to an enclosed ground flare, higher than the assumed destruction efficiency of 98% assumed by the BAAQMD for all other flares. This VOC destruction efficiency is valid under all wind conditions, as the enclosed ground flare is completely protected from crosswinds.

A single enclosed ground flare could readily accept a maximum gasifier startup flare gas flow. An additional backup elevated flare may also be required to handle much larger malfunction events, not disclosed in the Application. Flares, either enclosed ground flares or elevated emergency flares, are relatively inexpensive pieces of equipment. The capital cost of an enclosed ground flare capable of handling 100 tons per hour of VOCs is approximately \$4 to \$5 million. An elevated flare capable of handling ten times this heat input under force majeure emergency conditions costs approximately \$1.5 to 2 million.

Flare BACT would be an enclosed ground flare to combust gasifier startup off-gases and an elevated flare, for all unplanned flaring events that exceed the capacity of the enclosed ground flare. The addition of an enclosed ground flare, while costing several million dollars, must be considered in the context of this multi-billion dollar project.²⁴⁰ The BACT analysis did not evaluate a ground flare, but rather dismissed it as not available, without any explanation. The Application argues that “[a]n elevated flare is required to prevent the potential for excessive radiative heat and harmful concentrations of certain pollutants if the flare were to malfunction. Furthermore, with an elevated flare, the products of combustion () can be dispersed above working areas to reduce the effects of nose, heat, and other objectionable attributes.”²⁴¹ No support for these claims is provided.

²³⁹ Ap., v. 1, p. 6-3.

²⁴⁰ Kentucky NewGas Project Overview, ConocoPhillips, Peabody, available at <http://www.kentuckynewgas.com/wp-content/uploads/2008/12/ProjectFactSheet1.pdf> (stating that “Kentucky NewGas is a multi-billion dollar project in Western Kentucky”), attached as Ex. 74.

²⁴¹ Ap., v. 1, p. 6-3.

This is contrary to the experience and findings of the BAAQMD, reported above.²⁴² Further, it is contrary to U.S. EPA analyses²⁴³ and vendor experience, who report no visible flame, virtually no radiation (refractory-line combustion chamber), very low noise (enclosed), high destruction rates, and long service life.²⁴⁴

In an enclosed flare, the burner heads are located inside of an internally insulated shell. This shell reduces noise, luminosity, and heat radiation and provides wind protection, contrary to the unfounded allegations in the Project Summary. Further, stable combustion can be obtained with a lower Btu content gas, such as raw syngas, due to isolation from wind effects.

An enclosed flare, for example, includes the John Zinc ZTOF system, which encloses the flame in a refractory lined combustion chamber, effectively eliminating any visible emissions. No thermal radiation is emitted, contrary to the Project Summary's claim. In addition to providing a non-visible flame without thermal radiation, the ZTOF significantly reduces noise levels, again contrary to the unsupported claim in the Application. Full-load noise of less than 85 dBA adjacent to the flare is typical. Special acoustical wind fences can achieve 70-75 dBA. These flares can burn anywhere from a few hundred pounds per hour to as high as several hundred thousand pounds per hour.²⁴⁵

G. BACT WAS NOT REQUIRED FOR THE POWER BLOCK

The power block will generate 602 MW (net) of electricity from two combustion turbines operated in combined cycle mode. In combined cycle mode, the turbine exhaust is routed to a heat recovery steam generator ("HRSG") where the heat is recovered as steam which is used to drive a steam turbine. The exhaust from the HRSG is then vented to atmosphere at the stack. One turbine will operate as a baseload unit and the second as an intermediate load unit. The intermediate load unit would run depending upon relative revenue from generating electricity versus selling SNG.²⁴⁶

²⁴² See also San Joaquin Valley Air Pollution Control District Rule 4311, which sets VOC limits on unassisted enclosed ground flares of 0.0013 lb/MMBtu, which is four times lower than VOC emission rate assumed for the elevated flare or 0.0054 lb/MMBtu (Ap., v. 1, p. C-7).

²⁴³ U.S. Environmental Protection Agency, Benefits of an Enclosed Gob Well Flare Design for Underground Coal Mines, Addendum to: Conceptual Design for a Coal Mine Gob Well Flare, Report EPA 430-R-99-012, August 1999, <http://www.epa.gov/cmop/docs/022red.pdf>, attached as Ex. 75.

²⁴⁴ John Zinc, Flare Systems, http://www.johnzink.com/wp-content/uploads/flare_SYSTEMS1.pdf, attached as Ex. 76; John Zinc, Refining & Petrochemical Flares, p. 10, <http://www.johnzink.com/wp-content/uploads/refining-petrochemical-flares.pdf>, attached as Ex. 77; Charles E. Baukal, Jr. (Ed.), The John Zinc Combustion Handbook, CRC Press, New York, 2001, pp. 241, 622-623; Stone and others, Chapter 7, Flares, http://www.gasflare.org/pdf/Flare_Type.pdf, attached as Ex. 78; Callidus Technologies, Flares, http://www.premac.co/pdf/Callidus_Flare.pdf, attached as Ex. 79.

²⁴⁵ John Zinc, Zink Thermal Oxidizer Flare, <http://www.johnzink.com/wp-content/uploads/zink-thermal-oxidizer.pdf>, attached as Ex. 80.

²⁴⁶ Project Summary, p. 41.

1. The NOx Limit for the Power Block Is Not BACT

The Application concludes that BACT for nitrogen oxides (“NOx”) during normal operation is a NOx limit of 2 parts per million (“ppm”) at 15% O₂ based on a 3-hour rolling average, achieved using SCR.²⁴⁷ The top-down BACT analysis does not contain any support for these choices, such as a conventional ranking or hierarchy table,²⁴⁸ supported by stack tests, other permit limits, vendor literature, etc. The limit simply appears.²⁴⁹ In fact, the record contains no evidence that IEPA considered any other emission limit save the unsupported limit put forth by the applicant as BACT. The NSR Manual requires that “the most-effective control option not eliminated in step 4 is selected as BACT.”²⁵⁰ There is no evidence that the proposed BACT limit is the most-effective control option. Information in the Application itself indicates that it is not.

We agree with the technology choice of selective catalytic reduction (“SCR”) and the numeric portion of the BACT limit, 2 ppm at 15% O₂, but disagree that a 3-hour rolling average satisfies PSD and BACT. Neither the Application nor the IEPA Project Summary provides any basis for the selection of a 3-hour rolling average rather than a more stringent 1-hour average.

The averaging time is the time period over which a limit is averaged. A 3-hour rolling average averages the data in 3-hour chunks, moving forward 1-hour at a time. A moving average smooths out short-term fluctuations in the data. The shorter the averaging time, the more stringent the emission limit as there is less time to average out short-term spikes. This is shown by Figure 1 which shows that the 4-hour average conceals the considerably higher short-term spikes.

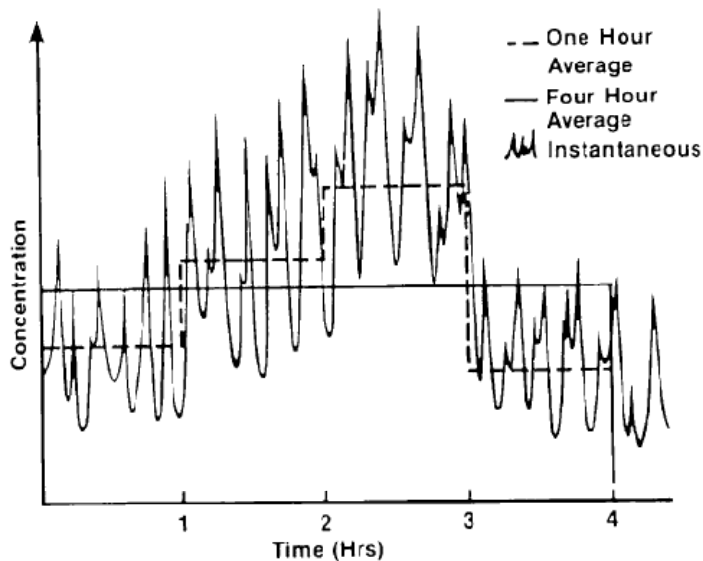
²⁴⁷ Ap., v. 1, p. 7-4 and Project Summary, p. 41.

²⁴⁸ NSR Manual, Sec. IV.C.3 and Table B-2.

²⁴⁹ See, e.g., Ap., p. 7-5.

²⁵⁰ NSR Manual, p. B.53.

Figure 1
The Effect of Averaging Time on Pollutant Concentration²⁵¹



The averaging time is part of the BACT determination.²⁵² The shorter the averaging time, the more stringent the emission limit. The Applicant must demonstrate that the BACT limit is the emission rate based on the maximum degree of reduction that is achievable. This demonstration has not been made and, in fact, is refuted by information in the record. Appendix D of the Application summarizes BACT determinations for other similar facilities. This summary includes 36 BACT determinations for NO_x for similar gas turbines at 2 ppm. Of these, 14 are based on a 1-hour averaging time.²⁵³ The Application contains no explanation for why these more stringent BACT determinations for similar turbines firing natural gas are not NO_x BACT for Taylorville.

Many other similar facilities have been permitted with a NO_x emission limit of 2 ppm at 15% O₂ and a 1-hour averaging time. Some of these not included in the Application are summarized below in Table 12.

²⁵¹ Thad Godish, Air Quality, 2nd Ed., Lewis Publishers, 1991, Figure 7.1, p. 216.

²⁵² NSR Manual, p. B.56.

²⁵³ Ap., v. 1, Appx. D, Table D-3, pp. D-26 to D-28.

Table 12
NOx Emission Limits Based on 1-Hour Averages*

Facility	NOx (ppmvd @ 15% O₂)
SMUD Clay Station, SMAQMD	2
IDC Bellingham, MA	2.0/1.5
Sacramento Municipal Utilities District, Consumnes	2
Sunset Power, SJVAPCD	2
Morro Bay – Duke	2
CPV Warren, VA-0308	2

* From: Bay Area Air Quality Management District, Statement of Basis for Draft Amended Federal “Prevention of Significant Deterioration” Permit, Russell City Energy Center, December 8, 2008; available at: http://hank.baaqmd.gov/pmt/public_notices/2008/15487/B3161_nsr_15487_sb-corrected_121208.pdf.

Regardless, a 1-hour averaging time must be established to protect short-term ambient standards, in particular the 1-hour nitrogen dioxide (“NO₂”) NAAQS.²⁵⁴ The modeling made specific assumptions about the maximum NOx emissions that occur during any one hour period to demonstrate compliance with this standard. Thus, there must be a 1-hour limit in the permit to protect the NAAQS, either the BACT limit or another 1-hour limit. The Draft Permit contains no 1-hour limits on emissions of NO₂ from the gas turbines. The separate startup and shutdown limits discussed in the next section are not based on a 1-hour average but rather are expressed on a per-event basis. The Draft Permit does not limit the duration of these events, but the Application indicates that the expected duration of a cold start, which has the highest emissions, is 2.4 hours.²⁵⁵

A 3-hour average can mask shorter-term emission spikes that would violate the 1-hour NOx NAAQS. A 3-hour average, for example, would allow all of the emissions to occur during one hour, effectively tripling the mass emission rate assumed in the 1-hour modeling. This type of event is hidden by a BACT limit based on a 3-hour average. Thus, the averaging time for the BACT limit must be no longer than the shortest NAAQS averaging time, which is 1 hour for NOx.²⁵⁶

2. The Draft Permit Fails to Satisfy BACT Requirements for Startup and Shutdown of Gas Turbines in the Power Block

The Draft Permit in Section 4.2.2 exempts startups, shutdowns, and malfunctions from BACT limits for NOx, CO, VOM, and CO₂. Separate limits are set in Condition 4.2.6(a) (Attachment 1, Table I) for startups and shutdowns. The Draft Permit is silent as to BACT for malfunctions.

²⁵⁴ See, e.g., NSR Manual, p. B.56; *In re Mississippi Lime*, slip op. at 42.

²⁵⁵ Ap., c. 1, pp. 7-14 to 7-15.

²⁵⁶ See, e.g., *In re Mississippi Lime Company*, slip op. at 42-45; *In re NMU*, slip op. at 50-51.

However, this table does not identify these limits as BACT limits or as satisfying BACT. The Project Summary at 55 suggests these are BACT limits,²⁵⁷ but the Application does not contain a BACT analysis for them, rather only an unsupported assertion that they are BACT.

a. No BACT Analysis

The Application justifies setting these separate limits “in order for CCG to propose limits that are both “achievable” and keep the CCCTs under a high degree of control during normal steady-state operation...”²⁵⁸ However, the origin of these “secondary BACT limits” is unknown. There is no information on how they were derived, *e.g.*, through a top-down BACT process, to avoid exceeding air quality standards, as turbine vendor guarantees, etc. They are simply stated as permit conditions with no support.

Periods of startup and shutdown are part of normal operating procedure. As such, they must be included in the BACT analysis. *See, e.g., In re Tallmadge Generating Station*, PSD Appeal No. 02-12, slip op. at 24 (EAB May 21, 2003) (“BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown.”); *In re Louisville Gas & Electric Co.*, slip op. at 10 (Sept. 10, 2008) (“A PSD BACT limit must apply at all times, unless the permitting authority determines the need to establish alternative BACT limits for periods of startup or shutdown, and justifies such limits as part of a complete BACT analysis.”)²⁵⁹

Exemption of a source “from any *concentration* limits during startup and shutdown,” including short-term limits, is “potentially a... serious concern.”²⁶⁰ An applicant cannot avoid BACT emission limits during periods of startup and shutdown through weak and improper secondary limits.

There is no evidence in the record that these startup and shutdown limits are BACT limits, which must represent the maximum degree of reduction achievable at all levels of operation, as indicated by the requirement that the limits be met on a continual basis. If an applicant is seeking secondary limits for startup/shutdown, certain demonstrations must be made and a specific process must be followed in setting such secondary limits as set out below.

As required with all BACT limits, IEPA must provide an explanation of how it arrived at the limits. Here, the limits provided for startup/shutdown are completely arbitrary because there

²⁵⁷ Project Summary, p. 55 (“The BACT limits for periods of startup and shutdown which are expressed in pounds per event, are also imposed to protect air quality. They set a cap or ceiling on allowed emissions, consistent with USEPA guidance for setting BACT for periods of startup, shutdown and malfunction.”)

²⁵⁸ *Ap.*, v. 1, p. 7-14.

²⁵⁹ *See also* Memorandum from John B. Rasnic, EPA Stationary Source Compliance Division, to Linda M. Murphy, U.S. Environmental Protection Agency, Region 1, *Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD* (January 28, 1993) (“Rasnic 1993 Memorandum”), attached as Ex. 81; Memorandum from Kathleen M. Bennett to Regional Administrators, Re: Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions, (Feb. 15, 1983) (“Bennett 1983 Memorandum”), attached as Ex. 82. We note that BACT covers periods of so-called malfunction to the extent that the malfunction could have been anticipated and avoided through proper maintenance.

²⁶⁰ *In re Indeck-Niles Energy Center*, PSD Appeal No. 04-01, 13 E.A.D. 126, 170-181 (E.A.B. Sept. 27, 2006).

is no explanation as to how they were determined. There is no linkage between the limit set, the relevant piece of control equipment, the extent to which it will be operational during startup/shutdown, and the degree to which it will effectively control for the relevant pollutant.

Consequently, there must be a discussion regarding each piece of control equipment that identifies its relevant design parameters, their limitations, the pollutants impacted, and accommodations of those limitations. The Draft Permit does not meet these BACT requirements because there is no discussion relating to startup and shutdown sequence for any of the control equipment, *i.e.*, the low NO_x combustors and the SCRs. For each of these pieces of control equipment the Draft Permit is deficient because it does not provide the following:

- (i) a list of key design parameters that affect the control device and its efficiency;
- (ii) how these key design parameters vary or change during startup and shutdown;
- (iii) critical levels of each of the design parameters, below or above which, the device cannot be operated without damage;
- (iv) options for how the design of the control device can accommodate a wider range of safe and effective operations.

Without following this process and including such a discussion, the secondary limits do not meet BACT requirements.

b. All Feasible Control Options Were Not Considered

The Draft Permit requires that the “secondary BACT limits” be achieved using “good air pollution control practices” without explaining what this means or why other more effective controls were not selected.²⁶¹ There is no evidence in the administrative record demonstrating that IEPA considered ways to eliminate or reduce excess emission during startup and shutdown to meet compliance obligations under the CAA.²⁶²

The plan that would presumably address these options, the “startup, shutdown, and malfunction plan” would be submitted in the future.²⁶³ This plan is outside of the four corners of the permit and therefore is not enforceable. Further, it is not available to the public and will be developed after the permitting process, therefore violating public participation requirements.

The Applicant and IEPA failed to consider ways to reduce emissions during startup and shutdown as part of the permitting record.²⁶⁴ It is feasible, for example, to preheat the SCR catalyst using an auxiliary boiler to allow NO_x control before 60% operation.

²⁶¹ Draft Permit, Cond. 4.2.2.d and 4.2.5-1.c.

²⁶² See, *In re Tallmadge Generating Station*, slip op., pp. 26-27.

²⁶³ Draft Permit, Cond. 4.2.5-2.

²⁶⁴ See *In re RockGen Energy Center*, 8 E.A.D., p. 553.

c. No Averaging Time

The averaging time and duration of the startup and shutdown events covered by these limits are not stated. Thus, even assuming they are BACT limits, the limits are incomplete as they include no averaging time. This is critical, for example, for pollutants with NAAQS and PSD increments with short averaging times, such as the one-hour NAAQS for NO₂, SO₂, and CO.

H. BACT WAS NOT REQUIRED FOR EQUIPMENT LEAKS

Emissions from equipment leaks can be controlled by eliminating them at the source with leakless components, such as welded connectors. They can also be reduced by using various leak detection and repair (“LDAR”) programs that monitor each component or group of components for leaks and repair them when found.

The Application evaluated several technically feasible control options for equipment leaks using the top-down BACT process, as summarized below in Table 13.

Table 13
(Ap., Table 6-2)

Control Option for VOM Emissions from ELCs	Estimated Effectiveness
“Leakless” Components (not including PRVs)	~100%
Routing PRVs to Add-On Controls (only PRVs)	90 to 99%
LDAR Program (all components) ⁶⁶	85 to 97%
Area OVA Monitoring Program (all components) ⁶⁷	<85%
Good Work Practices (all components) ⁶⁸	<30%

The Application concluded that leakless components are not cost-effective for any components in any service. The Application also concluded that an LDAR or other monitoring program was not cost-effective for any component or groups of components that it evaluated. These conclusions are based on numerous erroneous assumptions, which, when untangled, reveal that the top technology is in fact cost-effective for all components in all services, except heavy liquid service.

Instead, the Applicant proposed to implement a “MACT-equivalent” LDAR program for components in high VOM or H₂S service without performing a cost analysis.²⁶⁵ This proposed

²⁶⁵ Ap., v. 1, Sec. 6.6, p. 6.48 to 6-51.

program addresses about 15% (3,664) of the 24,864 components. The Applicant also proposed implementing good work practices, the least effective option, for all fugitive components, also without performing a cost analysis as it claimed it was infeasible to estimate performance.²⁶⁶

1. All Feasible Controls Were Not Analyzed

The critical first step in a BACT analysis is to ensure that all potential control options are identified. As the EAB has explained, the goal at this step is to cast as wide a net as possible so that a “comprehensive list of control options” is compiled. *In re Knauf*, 8 E.A.D. at 130.

The Application mentioned LDAR programs in passing but did not explain what they are, how they work, or the factors that determine their effectiveness. Instead, it eliminated plant-wide LDAR based on a cost-effectiveness analysis assuming a “HON-equivalent LDAR program,” without ever explaining what that means. The Application must be revised to consider a range of LDAR programs that includes the most-effective to satisfy BACT. Some of the additional controls that should be evaluated are discussed below.

a. More Effective LDAR Program

The most basic elements of an LDAR program are the definition of a leak (expressed as parts per million of the leaked substance), the frequency of monitoring, and the timeline in which leaks are repaired once discovered. The Bay Area Air Quality Management District (“BAAQMD”) has demonstrated that stricter regulation is feasible than contemplated in the BACT analysis or required in the Draft Permit.

The BAAQMD supervises LDAR programs at 5 refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under Regulation 8, Rule 18 (Reg 8-18). This regulation, first adopted in 1998, sets lower leak limits, more frequent inspections, and shorter repair schedules than evaluated in the BACT analysis or ultimately required as “MACT-like” LDAR in the Draft Permit, as summarized in Table 14, below.

²⁶⁶ Ap., v. 1, Sec. 6.6, p. 6-49.

**Table 14
Comparison of Draft Permit LDAR Program with BAAQMD Rule 8-18**

	Draft Permit	BAAQMD Rule 8-18
Leak definition – valves in gas/vapor/light liquid services	500 ppm	100 ppm
Leak definition – pumps, compressors in light liquid service	2,000 ppm	500 ppm
Inspection frequency	Monthly/annual	Quarterly/annual ²⁶⁷
Repair schedule	15 days	7 days ²⁶⁸

Another key aspect of an LDAR program is the scope of any exemptions recognized by the program. The LDAR program evaluated in the BACT analysis exempts leaks that are “unsafe” or “difficult” to monitor.²⁶⁹ The BAAQMD rule does not recognize such an exemption, as it is not consistent with BACT, given the BAAQMD’s experience. The BACT analysis must include all feasible LDAR programs, including one as effective as is currently in use within the BAAQMD.

In particular, in order to avoid the need to monitor such unsafe equipment leaks, components that qualify for difficult or unsafe to monitor or repair should be required to use leakless designs. This should be cost-effective as (1) the cost of monitoring, repairing and re-monitoring devices that are difficult to monitor is substantially higher than components in more convenient locations and (2) the potential emissions from leaking “inaccessible” components is greater since a leak is less likely to be observed visually or by sense of smell and instrumented monitoring only occurs annually.

The BACT analysis also did not consider requiring that “repeat offenders” be replaced. The South Coast Air Quality Management District and the Ventura County Air Pollution Control District each have rules under which components that have been subject to repair more than, *e.g.*, 5 times within a year be replaced with BACT/BARCT or be vented to an approved air pollution control device.²⁷⁰

Finally, IEPA must ensure the integrity of any LDAR program. As U.S. EPA’s history of enforcement actions demonstrates, this integrity cannot be taken for granted.²⁷¹ The U.S. EPA has encountered significant fraud in the conduct of LDAR inspections and in the reporting of

²⁶⁷ Pumps are subject to daily visual inspection. If a valve has not been found to be leaking during five quarterly inspections, the inspection frequency is reduced to once per year.

²⁶⁸ If the leak is detected by BAAQMD personnel during an inspection it must be repaired within 24 hours. The BAAQMD rules also require that leaks detected by the source be minimized within 24 hours.

²⁶⁹ Draft Permit, Cond. 4.9.6.a.

²⁷⁰ *See*, SCAQMD Rule 1173(g)(3) and Ventura County APCD Rule 74.7. Under the Ventura County rule, for example, if a valve is found to have suffered 5 major leaks in a year it shall be replaced by a valve with a bellows seal, or with graphite, PTE or PTFE stack chevron seal rings, or with BACT technology level components.

²⁷¹ For a more recent example, *see* U.S. EPA’s recent refinery settlements. *See, e.g.*, <http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html>.

results.²⁷² To avoid this, IEPA must include safeguards in the Permit, including requiring a professional engineer to sign off on all LDAR reports. IEPA must also explore requiring periodic independent audits of LDAR programs, at least for the largest emitters.

b. Monitoring Methods

The U.S. EPA runs a program to help industrial sources identify and implement best practices for reduction of methane emissions, known as Natural Gas Star.²⁷³ Several of the recommended technologies and practices²⁷⁴ may be applicable to equipment leaks. For instance, one project describes the use of optical imaging in a directed inspection and maintenance program. Handheld infrared cameras are used to identify, in real time, process components that are leaking.²⁷⁵ Additional imaging technologies, including the use of DIAL (Differential Absorption Light Detection and Ranging), can also be used to identify fugitive sources of VOCs.²⁷⁶ The existing LDAR program could be expanded to process units not currently covered (e.g., cooling towers).²⁷⁷ “Smart” LDAR programs are also being implemented as a means of minimizing fugitive process losses. These options must be evaluated as a part of a complete BACT analysis for fugitive VOC emissions from flanges.

Optical scanning programs can be a part of an overall improved LDAR program. Use of optical cameras involves some modest level of investment; however, once purchased, these devices can provide an extremely low cost means of filling the gaps in the LDAR program. Daily or weekly scans can identify plant areas containing gross emitters (including “unsafe to monitor” or “difficult to monitor” components) for targeted LDAR inspections. Such inspections could replace scheduled inspections and save operators money by detecting leaks

²⁷² In the late 1990’s, EPA discovered flagrant, industry-wide violations of several CAA requirements at the nation’s refineries. Among the most significant violations were LDAR rules violations where refiners, and independent contractors hired by refiners, routinely underreported by up to a factor of 10 the number of leaking valves, leading to significant excess emissions. The ensuing enforcement actions led to 29 settlements with operators over 90% of the refining capacity in the country. These settlements required improved LDAR practices, \$82 million in fines, and \$75 million in Supplemental Environmental Projects. This experience demonstrates a need for detailed independent oversight of LDAR activities, as does the recent Pelican refinery criminal prosecution.

²⁷³ U.S. Environmental Protection Agency, Natural Gas Star; <http://www.epa.gov/gasstar/index.html>.

²⁷⁴ U.S. Environmental Protection Agency, Natural Gas Star, Recommended Technologies and Practices; <http://www.epa.gov/gasstar/tools/recommended.html>.

²⁷⁵ See, e.g., Technology Transfer: Optical Leak Imaging for the Hydrocarbon Industry, ICF Consulting, available at http://www.icfi.com/Markets/Environment/doc_files/optical-leak-imaging.pdf, attached as Ex. 86

²⁷⁶ See, e.g., Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection, Alberta Research Council, November 2006, available at <http://www.arc.ab.ca/areas-of-focus/carbon-conversion-capture-and-storage/cccs-publications-and-resources/dial-emission-reports/>, attached as Ex. 87; see also Fugitive VOC-emissions measured at Oil Refineries in the Province of Västra Götaland in South West Sweden, 2003, available at <http://www.spectrasyne.ltd.uk/ROSEVOCreport.pdf>, attached as Ex. 88.

²⁷⁷ CARB, Reducing Greenhouse Gas Emissions from California Refineries, April 2008, available at <http://www.capcoa.org/climatechange/upload/documents/Presentation-04-11-2008-WorkshopPresentationRefineries4-11.pdf>; attached as Ex. 27, see also Texas Environmental Research Consortium, Project H7-A: Compilation of Information on Cooling Towers, Equipment Fugitive Leaks and Flares, November 30, 2003, attached as Ex 89.

early, while improving the environmental performance of the facility. Use of optical scanning devices, pressure relief valves, monitoring devices and other technical advances can complement existing programs. However, the suite of existing options have not demonstrated the ability to provide the level of emission reductions as can be obtained from well-designed and implemented LDAR programs. For this reasons these options must be considered in addition to and not *in lieu of* existing programs.

2. The LDAR Cost-effectiveness Analysis Was Flawed

The Application, Project Summary, and Draft Permit do not require any source controls for any of these components, *i.e.*, leakless components. The Application argues that leakless components are not cost-effective²⁷⁸ and IEPA apparently accepts this conclusion without vetting its underpinnings.²⁷⁹ The best available control technology analysis for fugitive components is flawed because it eliminated technically feasible controls, widely used in new facilities, based on a flawed cost analysis.

The cost-effectiveness analysis erroneously rejected the top controls based on a number of errors including the following:

- (1) failed to demonstrate costs are unreasonable by comparison to costs borne by other similar sources;
- (2) underestimated uncontrolled emissions by using the lowest published emission factors for a non-representative source, as explained in Section II.D.1 rather than the maximum, as required for a potential to emit calculation;
- (3) underestimated emission reductions for leakless components by assuming LDAR controls in place for highest emitters;
- (4) evaluated wrong greenhouse gas pollutant;
- (5) failed to include all controlled pollutants in calculating dollars per ton of pollutant removed;
- (6) overestimated and unsupported capital cost; and
- (7) excluded connectors.

Finally, the Draft Permit conditions do not assure that the assumptions that were used in the cost-effectiveness analyses are actually realized as it requires no demonstration at all of actual emissions or any of the assumptions that went into the emission calculations.

²⁷⁸ Ap., v. 1, Sec. 6.6.1.4, p. 6-47 (\$733,035/ton).

²⁷⁹ Project Summary, pp. 72-75.

a. The Cost Analyses Fail to Demonstrate an Adverse Economic Impact

The top technologies, leakless components and LDAR, were eliminated in Step 4 of the top-down BACT analysis for each PSD pollutant as not cost-effective. In each case, the cost-effectiveness in dollars per ton is estimated and rejected as not cost-effective with no explanation for why the estimated dollars per ton is not acceptable. Rejection language includes: “cost infeasible,” (v. 1, p. 6-42), “clearly not economically feasible” (v. 1, p. 6-48), and “not economically feasible” (v. 1, p. 6-49). Rejection of a control alternative as not cost-effective requires comparison with the range of costs normally associated with BACT for similar facilities.²⁸⁰ The Application does not contain any comparative cost data, even though leakless components and LDAR programs have been required for many similar processing facilities.²⁸¹

The relevant question is whether the cost of the BACT control is disproportionate compared to other plants using the same control. The Application does not disclose the range considered to be cost-effective, but rather rejects all cost-effectiveness values, even those routinely considered cost-effective for other similar sources. If the cost of a technology in dollars per ton is on the same order as the cost previously borne by other sources of the same type in applying that control, the control should initially be considered economically achievable and therefore acceptable as BACT.²⁸² The Application did not present any cost-effectiveness data for other similar sources, but rather rejected estimated costs with no explanation.

Some of the cost-effectiveness values reported in the Application are clearly cost-effective before any of the corrections recommended in these comments are made. These include the cost of a facility-wide LDAR program estimated to cost \$5,403 per ton of CO removed²⁸³ and \$207/ton of methane as CO₂-equivalent emissions of greenhouse gases or CO₂e (“CO₂e”) removed.²⁸⁴ Mississippi Lime, for example, reported a cost-effectiveness range of up to \$5,000 to \$10,000 per ton for criteria pollutants and²⁸⁵ SIE assumed a threshold of \$10,000/ton in its cost analysis for a similar gasification project.²⁸⁶ The Application itself concedes that

²⁸⁰ NSR Manual, Sec. IV.D.2.c.

²⁸¹ See, for example, TransGas Permit (Ex. 72) Cond. 4.1.9, p. 32 (e.g., pumps in hydrocarbon service and valves are required to have sealless design; 915 of 1,045 total connectors are required to be welded together.).

²⁸² NSR Manual, p. B.44. *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, slip op. at ____; *In re Masonite Corp.*, 5 E.A.D. 551, 554 (EAB 1994). .

²⁸³ Ap., v. 1, p. 6-49, Table 6-4.

²⁸⁴ Ap., v. 3, p. 6-39, Table 6-7.

²⁸⁵ Illinois Environmental Protection Agency, Project Summary for an Application for Construction Permit/PSD Approval from Mississippi Lime Company for a Lime Manufacturing Plant in Prairie Du Rocher, Illinois, October 4, 2010; <http://www.epa.state.il.us/public-notice/2010/mississippi-lime-pdr/project-summary.pdf>, attached as Ex. 90.

²⁸⁶ Southeast Idaho Energy, LLC, Addendum 1 to the Application for Authorization to Construct the Power County Advanced Energy Center, July 1, 2008, p. 9, attached as Ex. 91. See also: Memorandum from John S. Seitz, OAQPS, Re: BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects, January 19, 2001 and San Joaquin Valley Air Pollution Control District, Final Staff Report, Update to Rule 2201 Best Available Control Technology (BACT) Cost Effectiveness Thresholds, May 14, 2008,

\$10,000/ton is a commonly accepted threshold for non-GHG pollutants,²⁸⁷ but fails to apply it in its own cost analysis.

A control alternative that has been found to be cost-effective in other similar applications cannot be rejected as BACT unless unusual circumstances exist and are documented in the record. As explained in the NSR Manual, "... where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source." The record contains no such documentation.

b. The Cost Analysis Evaluated the Wrong Regulated Greenhouse Gas Pollutant

The facility would emit several greenhouse gas ("GHG") pollutants, including CO₂, CH₄, and nitrous oxide ("N₂O"). The BACT analysis for component leaks separately evaluated each of these pollutants based on the weight of the compound. These analyses concluded there were no cost-effective controls. However, the regulated pollutants under PSD are CO₂-equivalent emissions of greenhouse gases or CO₂e, which takes into account the global warming potential of each individual pollutant.²⁸⁸

The difference in these metrics is material. The equipment leak CO₂ emissions amount to 177.4 ton/yr and the CH₄ emissions to 51.3 ton/yr. However, the CO₂e emissions are 1,255 ton/yr.²⁸⁹ These differences matter in the cost-effectiveness analysis used to reject all controls for component leaks. For example, the Application concluded that it would cost \$961 per ton of CO₂ removed to use an LDAR program, which is outside of the proffered range of \$3 to \$300/ton CO₂e. However, if CO₂e had been used in this cost calculation instead of CO₂, the cost-effectiveness would be \$113/ton CO₂e,²⁹⁰ which is well within the proffered acceptable cost-effectiveness range. Thus, when the correct regulated GHG pollutant is used to evaluate costs, a facility-wide LDAR program is cost-effective.

c. Emission Reductions Were Underestimated

Cost-effectiveness is the annual cost in dollars per year divided by the amount of each pollutant that is removed in tons per year. For a given annual cost, the higher the emission reductions, the lower the cost-effectiveness value and the more cost-effective the control. When emissions are underestimated, as here, cost-effectiveness in dollars per ton is overestimated.

<http://www.valleyair.org/busind/pto/bact/May%202008%20BACT%20cost%20effectiveness%20threshold%20update%20staff%20report.pdf>, attached as Ex. 92.

²⁸⁷ Ap., v. 3, p. 6-34.

²⁸⁸ 40 CFR 51.166.

²⁸⁹ Ap., v. 3, p. 3-4, Table 3-3.

²⁹⁰ Cost-effectiveness = (\$142,405/yr)/(1,255 ton/yr) based on Ap., v. 3, p. 6-35, Table 6-5 and p. 3-4, Table 3-3.

This can result in rejecting an economic control alternative as not cost-effective. This situation has occurred here.

i. *Components Controlled by LDAR*

The emissions reported in the Application in Table 3-2 and used to calculate emission reductions from installing leakless components²⁹¹ include LDAR on the highest emitters.²⁹² In other words, in evaluating the cost effectiveness of installing leakless components, the Application erroneously assumed that the emissions to be controlled had already been reduced by 85% to 97% by using LDAR. However, there is no need for LDAR when leakless components are used as there are no leaks. The cost effectiveness analysis should have used the uncontrolled emissions, without LDAR. This would have resulted in higher emission reductions and thus much lower cost effectiveness values.

ii. *Emissions Underestimated*

As explained in Section II.D, the Application significantly underestimated emissions from leaking components by using an anomalously low emission factor and overestimating the control efficiency. Thus, emission reductions achieved by leakless components and facility-wide LDAR were underestimated and cost-effectiveness overestimated.

d. The Cost Analysis Did Not Consider All Pollutants Controlled

The Application estimates the cost-effectiveness of BACT for equipment leaks on a pollutant-by-pollutant basis. It includes a separate cost analysis for CO,²⁹³ VOCs,²⁹⁴ CO₂,²⁹⁵ and CH₄.²⁹⁶ When calculating the cost of a control option, such as leakless components, which reduce emissions of numerous pollutants at the same time, the cost of that control option must be divided between the overall reductions in all pollutant emissions.

U.S. EPA guidance states that when a control option controls multiple pollutants the costs are to be apportioned to each pollutant before the dollars per ton is figured for cost-effectiveness.²⁹⁷ Responding to a question by Georgia permitting authorities on how to account

²⁹¹ Ap., v. 1, Tables 6-3; v. 3, Tables 6-4

²⁹² Ap., v. 1, Tables C-24.2, C-25.2, C-26.2, C-27.2 and v. 3, Tables A-16.2, A-17.2.

²⁹³ Ap., Vol. 1, p. 6-48, Table 6-3.

²⁹⁴ Ap., Vol. 1, p. 6-51, Table 6-5.

²⁹⁵ Ap., Vol. 3, p. 6-34, Table 6-4.

²⁹⁶ Ap., Vol. 3, p. 6-38, Table 6-6.

²⁹⁷ Letter from Brian L. Beals, Chief Preconstruction/HAP Section, U.S. EPA Air and Radiation Technology Branch, to Edward Cutrer, Jr., Program Manager, Georgia Department of Natural Resources, March 24, 1997 (Responding to a question by Georgia permitting authorities of how to account for a control device that reduces both VOC and CO, EPA agreed with the Georgia agency's interpretation that the cost-effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device."), attached as Ex. 93.

for a control device that reduces both VOC and CO, U.S. EPA agreed with the Georgia agency's interpretation that the cost-effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device." *Id.* Thus, in this case, the cost of leakless components and LDAR, which simultaneously reduce all pollutants otherwise emitted, must be divided by the total reduction of all pollutants reduced, *i.e.*, the sum of CO, VOC, H₂S, CO₂, and CH₄. This change alone reduces the dollars per ton of controlling these emissions to within the acceptable range. The IEPA has explicitly recognized this in a number of permitting actions, including for Universal Cement.²⁹⁸

The CO BACT analysis, for example, evaluated the cost-effectiveness of using leakless components on all valves in gas and light liquid service and all pumps in light liquid service, bundled together. This analysis considered only 3,228 components out of a total of 24,979 components, or only 13% of the total. All connectors and all components in heavy liquid service were excluded.²⁹⁹ Thus, cost-effectiveness is an incomplete basis for rejecting leakless components as BACT for CO.

The applicant's cost-effectiveness analysis for CO concluded that it would cost \$733,035 per year to remove 12 ton/yr of CO, resulting in a cost-effectiveness value of \$61,077/ton.³⁰⁰ Thus, it found leakless technology was not economically feasible to control CO emissions from the subject components.³⁰¹ However, these same 3,228 leakless components also simultaneously control other pollutants, including VOM, H₂S, CO₂, and CH₄.

We revised the cost-effectiveness analysis for leakless components to additionally include only GHGe, but otherwise using all of the Applicant's assumptions. The same components that emit 12 ton/yr of CO also emit 69 ton/yr of CO₂ and 12 ton/yr of CH₄. *See* calculations in Ex. 19.

The regulated PSD pollutant for greenhouse gases is greenhouse gas equivalents or GHGe, calculated as set out in 40 CFR 52.21(b)(49)(ii). The mass of each greenhouse gas is multiplied by the gas's associated global warming potential, which is reported in Table A-1 to Subpart A of 40 CFR Part 98. The global warming potential of CO₂ is 1 and of methane, 21. The GHGe emitted from these components is 69 + (12 × 21) or 321 ton/yr GHGe. Thus, the total amount of PSD pollutants eliminated by using leakless technology on these components is at least 333 ton/yr (small amounts of H₂S and VOM are excluded). The cost-effectiveness for

²⁹⁸ Illinois Environmental Protection Agency, Project Summary for a Construction Permit Application from Universal Cement, LLC, for a Portland Cement Manufacturing Plant in Chicago, Illinois, September 4, 2011, p. 21 (In discussing clean fuels: "Unlike the examination of an add-on control devices [sic], which commonly is focused on control of a specific pollutant or combined control for multiple pollutants..."); available at: http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CEEQFjAA&url=http%3A%2F%2Fwww.epa.state.il.us%2Fpublic-notices%2F2011%2Funiversal-cement%2Fproject-summary.pdf&ei=-F8CT8vCNpTaiQKA3oW6Dg&usg=AFQjCNGhbJHU8ZK_n7Z89r05-sgpDNGoHg, attached as Ex. 94.

²⁹⁹ Ap., v. 1, p. 6-46 and p. D-8.

³⁰⁰ Ap., v. 1, Table 6-3 and pp. D-9 to D-10.

³⁰¹ Ap., v. 1, p. 6-48 and Table 6-3.

these components, based on total pollutants removed, is \$2,200/ton.³⁰² This is well within the range of costs routinely considered to be acceptable for purposes of BACT. The costs would be lower yet if a more realistic estimate of emissions were used and other errors in the cost analysis were corrected.

Similarly, the CO BACT analysis rejected LDAR as BACT based on cost-effectiveness alone. This analysis assumed that all equipment leak components in CO or VOM service – 19,284 components – would be subject to an LDAR program that removed 93% of the CO. This analysis estimated that it would cost \$156,526 per year to implement this program and that it would remove 29 ton/yr of CO. The resulting cost-effectiveness, \$5,403/ton, was judged not economically feasible.³⁰³ This conclusion is incorrect, as this value is well within the range routinely considered cost-effective.

However, if this calculation had included all controlled pollutants, LDAR would have been found to be highly cost-effective. Emission estimates in the Application indicate the following emissions from the subject components, all of which would be reduced by the same 93% assumed only for CO:³⁰⁴

- CO: 30.51 ton/yr
- VOM: 2.44 ton/yr
- H₂S: 1.41 ton/yr
- CO₂: 177.4 ton/yr
- CH₄: 51.31 ton/yr or 1,077.5 ton/yr GHGe
- **TOTAL: 1,289.3 ton/yr GHGe**

We revised the cost-effectiveness analysis for LDAR for CO control to assume that 93% of each of these pollutants would be removed, but otherwise using all of the applicant's assumptions. This reduces the cost-effectiveness of a plant-wide LDAR program from \$5,403/ton to \$131/ton.³⁰⁵ If CH₄ is included in the calculation as the mass rate rather than GHGe, the cost-effectiveness is still only \$640/ton. These costs are at the lower end of the cost-effectiveness range. Actual cost-effectiveness would be much lower as this revised estimate does not address the fact that the Application significantly underestimates emissions from equipment leaks and makes a number of other errors that overestimate costs and underestimate emissions.

e. Unsupported and Overestimated Capital Cost Estimate

³⁰² Cost-effectiveness of leakless technology on valves in gas and light liquid service and pumps in light liquid service, based on all pollutants removed: ($\$733,035/\text{ton}/333 \text{ ton/yr}$) = \$2,201/ton

³⁰³ Ap., v. 1, pp. 6-49 to 6-50, Table 6-4 and pp. D-2 to D-4.

³⁰⁴ Ap., v. 1, Table 3-2 (for CO, VOM, H₂S) and v. 3, Table 3-3 (for CO₂ and CH₄).

³⁰⁵ Revised cost-effectiveness for plant-wide LDAR program, based on all controlled pollutants with methane expressed as GHGe: ($\$156,526/0.93 \times 1,289.26 \text{ ton/yr}$) = \$130.55/ton. With methane expressed on a mass basis: ($\$156,526/0.93 \times 263.07 \text{ ton/yr}$) = \$639.78/ton.

i. No Basis

The starting point of the cost-effectiveness analyses for leakless components, the additional capital cost per component, is taken directly from the Kentucky NewGas Application, prepared by the same consultant, Trinity Consultants.³⁰⁶ In fact, the text and conclusions of the cost analyses in these two applications are nearly identical, indicating a cut-and-paste job. Neither application provides any basis for the claimed additional capital cost for the various control options.

ii. Installation Cost

The cost analyses for leakless components assume that the cost to install leakless valves and pumps is 25% of the capital cost of the components.³⁰⁷ No basis is provided. This is a common assumption for complex add-on pollution control equipment, such as an SCR, that involves site preparation, foundation, erection, painting, etc. However, for leakless valves and pumps, the only relevant installation costs are those that would be incurred in addition to installing a normal valve or pump in the same location. There is no additional installation cost for a leakless component as the seal and other modifications that render the component leakless are internal to the component. The installation costs should be the same. Thus, in our revised cost estimates below, we have set installation costs to zero.

f. The Cost Analysis for Leakless Components Excluded Connectors

The Application does not provide any cost estimate to eliminate leaks from the 18,798 connectors proposed for Taylorville. These leaks could be completely eliminated at a net savings by welding connections instead of using bolted or other flanged connections. This would reduce emissions and the cost per ton by significant amounts. Instead, the Application simply dismisses leakless connectors, without even discussing them, erroneously arguing emission factors for connectors are 70% less than for valves and pumps, which were costed³⁰⁸ and implausibly claiming they are not available.³⁰⁹ This argument is wrong and results in rejecting welded connections, the top control that is widely used in new facilities, as not cost-effective without any analysis at all.

In fact, connectors make up the majority of the fugitive components, 18,798 or 75% of the total, and are responsible for 42% of the emissions. Thus, they should not be dismissed as not cost-effective based on the relative magnitude of emission factors and the purported cost of valves and pumps, without any analysis. Welded connections are less costly than flanged connections and if the emissions from these had been included in the cost analyses, the increase

³⁰⁶ Ap., v. 1, Appx. D, Tables D-2.3, D-2.4 and v. 3, p. 6-32.

³⁰⁷ Ap., v. 1, pp. D-9 (CO), D-12 (VOM), Table D-2 and v. 2, p. B-2 (GHG).

³⁰⁸ Ap., v. 1, pp. 6-46, D-8 and v. 3, p. 6-33.

³⁰⁹ Ap., v. 1, p. D-8, note 2.

in cost would have been zero or negative and leakless technology for all components would have been cost-effective and thus required for all components.

Pipes, valves, pumps and other equipment are commonly connected using flanges that are welded or screwed. Flanged joints are made by bolting together two flanges with a gasket between them to provide a seal. The most commonly used flange types in the petroleum and chemical industry are:

- Welding neck flange
- Slip on flange
- Socket weld flange
- Lap joint flange
- Threaded flange
- Blind flange

These joining methods leak, no matter how carefully executed. Further, flanged pipe system need much more space, *e.g.*, pipe racks. Insulation of flanged pipe systems is more expensive due to the need for special flange caps. There are no standards that define whether or not flange connections may be used. In a newly built facility, it is customary to minimize flanged connections, because only one weld is needed to connect two pieces of pipe. This saves on the capital costs of two flanges, the gasket, the stud bolts, the second weld, the cost of non-destructive tests for the second weld, etc. Welded connections, which eliminate 100% of the emissions, generally cost less than other joining methods that do have emissions.³¹⁰ However, here, the Application has assumed the old, non-BACT flange joining method, which does not satisfy BACT, we presume because including their emissions would render all leakless components cost-effective.

In sum, the use of leakless connectors does not increase cost, but significantly increase emission reduction. Thus, the inclusion of these components would improve the cost-effectiveness of leakless components. This will be considered in the following revised cost analysis.

g. Revised Cost Analysis for Leakless Components

The top control technology for equipment leaks is leakless components, which control 100% of emissions. These are widely used and have been required at existing refineries in Consent Decrees and at new facilities as BACT.³¹¹

³¹⁰ Definitions and Details of Flanges; http://www.wermac.org/flanges/flanges_general_part1.html, attached as Ex. 95; Fundamentals of Professional Welding; http://www.waybuilder.net/free-ed/BldgConst/Welding01/welding01_v2.asp.

³¹¹ See, *e.g.*, West Virginia Department of Environmental Protection, Division of Air Quality, Permit to Construct, TransGas Development Systems, LLC (Ex. 72), Cond. 4.1.9, p. 32 (*e.g.*, pumps in hydrocarbon service and valves are required to have sealless design; 915 of 1,045 total connectors are required to be welded together.)

We revised the cost analysis for leakless components to correct the errors in the Applicant's analysis discussed above. Our revised analysis is based on the following: (1) all leaking components will be replaced by leakless equivalents; (2) the increase in capital cost for a leakless connector is zero; (3) installation costs for leakless and non-leakless components are identical; (4) no sales tax on pollution control equipment; (5) emission reductions for all controlled pollutants based on the EPA refinery emission factors; and (6) emission reductions based on the sum of all PSD pollutants (VOM, CO, H₂S, CO₂, CH₄). Our detailed calculations are included in Exhibit 19, Tab Cost (2), and summarized in Table 15.

Table 15
Revised Cost Effectiveness Analysis for Equipment Leaks

Component	Service	Number	Total Annual Cost (\$/yr)	Regulated PSD Pollutant Emissions (tons/yr)					Total Emissions (ton/yr)	Cost Effect Mass (\$/ton)	Cost Effect GHGe (\$/ton)
				VOM	CO	H ₂ S	CO ₂	CH ₄			
Valves	Gas	3,138	520,938	82.89	75.66	12.13	469.95	97.57	738.21	706	194
	Lt. Liq.	1,195	198,381	20.97	19.14	3.07	118.89	24.68	186.75	1,062	292
	Heavy Liq.	1,536	254,991	0.32	0.29	0.05	1.79	0.37	2.81	90,827	24,929
Pumps	Lt. Liq.	47	247,598	5.15	4.70	0.75	29.20	6.06	45.87	5,398	1,481
	Heavy Liq.	45	237,062	0.89	0.81	0.13	5.03	1.04	7.90	29,990	8,231
Compressors	Gas	20	526,804	11.69	10.67	1.71	66.26	13.76	104.09	5,061	1,389
Connectors	Gas	12,147	0	3.02	2.75	0.44	17.11	3.55	26.87	0	0
	Lt. Liq.	3,283	0	2.65	2.42	0.39	15.04	3.12	23.62	0	0
	Heavy Liq.	3,368	0	1.66	1.51	0.24	9.40	1.95	14.77	0	0
TOTALS		24,779	1,985,773	129.24	117.96	18.91	732.67	152.11	1,151	1,725	474

Our analysis indicates that leakless components are highly cost-effective. The overall cost effectiveness of using leakless components on all valves, pumps, compressors and connectors is \$1,725 /ton on a mass basis and \$474/ton on a GHGe basis. These values are well within the range of acceptable costs. Further, when the various components are evaluated by type and service, the cost effectiveness is acceptable for all except valves in heavy liquid service (\$24,929/ton). All other cost effectiveness values are less than \$10,000/ton. Thus, leakless components should be required as BACT at least for all components except valves in heavy liquid service.

I. BACT WAS NOT REQUIRED FOR MATERIAL HANDLING OPERATIONS

The facility will emit PM, PM10, and PM2.5 from coal handling, including coal transfer points associated with the open inactive storage pile (TP1-3), wind erosion from the inactive storage pile (PIL1), and maintenance of the inactive storage pile (PIL1-3). The BACT analysis is flawed for each of these fugitive sources.

1. Inactive Storage Pile Emissions (TP1-3, PIL1-3)

The facility includes active and inactive coal storage piles. Particulate matter emissions – PM, PM10, and PM2.5 – are released from these piles due to wind erosion; loading/unloading; and maintenance operations. The Application concluded that BACT for the smaller pile is enclosure in a dome controlled by a baghouse. However, the Application concluded with no support that it is not feasible to enclose the inactive coal pile due to its large size, about 8 acres with a footprint of 600 feet × 600 feet and a height of 45 feet or about 600,000 cubic yards assuming a cube.³¹² Instead, the Application concluded that BACT for dust generating activities at the inactive pile is wet dust suppression and pile compaction.³¹³ This is not BACT for the inactive storage pile. As discussed below, the BACT analysis is incomplete and thus reached an erroneous conclusion.

a. The BACT Analysis Failed To Consider All Control Options

The BACT analyses evaluated three control options: (1) enclosures; (2) dust suppression; and (3) compaction.³¹⁴ There are other demonstrated control options for storage piles that are widely used but were not considered in the Application. These include: pile geometry and orientation to minimize wind erosion emissions, a wind fence system, location of the pile within the facility to minimize emissions and offsite impacts,³¹⁵ or modifying the geometry of the pile as required to facilitate enclosure. Many of these are required under some state regulations.³¹⁶ Further, combinations of these measures were not evaluated. Combinations of measures achieve a higher control efficiency than one alone.

b. Storage Domes Are Feasible for the Inactive Pile

The BACT analysis eliminated storage domes for the inactive pile, arguing it was too big to enclose, but providing no specific details. However, the BACT analysis did not disclose the shape of the piles, the design of any considered enclosure, and did not consider changing the geometry of the piles and domes to eliminate any perceived size constraints. The pile dimensions were reported as 600 ft by 600 ft by 45 ft high. The websites of dome vendors advertise enclosures up to 1000 feet in diameter.³¹⁷ Further, two equal-sized piles could be used

³¹² Ap., v. 1, Appx. C, Table C-12.3, p. C-46, note 1.

³¹³ Ap., v. 1, pp. 8-11 and 8-17.

³¹⁴ Ap., v. 1, p. 8-16.

³¹⁵ See discussion of dust emissions from a March 2006 web discussion; available at <http://www.bulk-online.com/Forum/showthread.php?t=7184>, attached as Ex. 97; California Association of Air Pollution Control Officers, Guidance on Storage Pile Fugitive Dust; available at http://www.capcoa.org/index.php?option=com_content&view=article&id=24%3Adust-storage-piles&catid=17%3Aag-clearinghouse-subcategories&Itemid=20, attached as Ex. 98.

³¹⁶ Air districts with aggressive fugitive dust control regulations that should be considered in BACT analyses: Districts within California: www.arb.ca.gov/drdb/drdb.htm; Clark County, NV,; www.co.clark.nv.us/air_quality/regs.htm; and Maricopa County, AZ. See also SCAQMD Rule 1158.

³¹⁷ A diameter of 327m (>1,000ft): <http://www.cargotransfer.net/pages/products/dome.php>, attached as Ex. 99; Clear span domes over 900 ft. for bulk storage: <http://www.cargotransfer.net/pages/products/adr04.php>, attached as Ex. 100.

instead of one large pile. Further, the inactive pile is sized to hold a 60 day supply of coal or about 310,000 tons. This is excessive. Storage piles are typically designed for a 30 day inventory.

Regardless, enclosure of material storage piles is common. In California, the South Coast Air Quality Management District's ("SCAQMD") Rule 1158³¹⁸ requires all new and most existing coal, coke, and sulfur piles to be covered. There is no size exclusion. The SCAQMD implemented this rule in 1999 in response to the failure of its previous fugitive dust rule to adequately control emissions.³¹⁹ The BACT analysis did not provide any site-specific reason or point to any unusual circumstances as to why enclosures can be used elsewhere, but not here.

The previous SCAQMD rule only required closed storage for coke piles and allowed an exemption if a facility developed a management plan to control fugitive emissions, as here. The SCAQMD found that "ambient monitoring studies, on-going complaints, and site visits by the [District staff] indicate that the current [rule] is not sufficient to reduce PM10 emissions and the potential for public nuisances."³²⁰ Thus, the SCAQMD adopted an updated rule that mandated enclosed storage for coke piles and broadened the rule to include coal and sulfur piles. This rule has been adopted into the SCAQMD's State Implementation Plan ("SIP"). The SCAQMD's experience is instructive as it shows that the methods proposed for Taylorville as BACT do not always provide adequate dust control and that enclosed storage is feasible and the superior control option.

The SCAQMD further found that enclosures are a cost-effective way to reduce particulate emissions. The SCAQMD obtained costs to construct various types of enclosures and found that they ranged from \$47/ton to \$120/ton of enclosure capacity.³²¹ Further, enclosing piles reduces or eliminates the need for chemical encrusting agents or dust suppressants, which can be expensive and also have significant non-air quality health and environmental impacts³²² that must be considered in a top-down BACT analysis, but were not. Enclosure options are the top technology as they essentially eliminate storage piles emissions. Numerous examples are listed in the SCAQMD Staff Report for Rule 1158.

³¹⁸ South Coast Air Quality Management District, Rule 1158 - Storage, Handling, and Transport of Coke, Coal and Sulfur, adopted December 2, 1983, amended June 11, 1999; http://www.arb.ca.gov/pm/pmmeasures/ceffect/rules/scaqmd_1158.pdf, attached as Ex. 101.

³¹⁹ South Coast Air Quality Management District, Agenda No. 28 for Board Meeting, June 11; <http://www.aqmd.gov/hb/1999/990628a.html>, attached as Ex. 102.

³²⁰ South Coast Air Quality Management District, Final Staff Report for Rule 1158, p. ES-2; available as an attachment to Agenda No. 28 for Board Meeting, June 11; <http://www.aqmd.gov/hb/1999/990628a.html>, attached as Ex. 103.

³²¹ South Coast Air Quality Management District, Staff Report, Appendix D, p. D-1; available as an attachment to Agenda No. 28 for Board Meeting, June 11; <http://www.aqmd.gov/hb/1999/990628a.html>, attached as Ex. 104.

³²² Thomas Piechota and others., Potential Environmental Impacts of Dust Suppressants: "Avoiding Another Times Beach," An Expert Panel Summary, Las Vegas, NV, May 30-31, 2002, U.S. Environmental Protection Agency, Report EPA/600/R-04/031, March 2004, p. v, attached as Ex. 105.

Recent permits and BACT analyses have required coal and coke storage to be enclosed. For example, the February 2009 BACT determination for the Southeast Idaho Energy facility, which will gasify coal and petcoke to produce fertilizer products, required coal and petcoke storage to be enclosed in silos vented to baghouses.³²³

2. The BACT Analysis Failed To Evaluate Control Effectiveness

The BACT analysis concluded that BACT was satisfied by “wet dust suppression” without assigning any control efficiency. The emission calculations, however, assume a 50% to 90% control efficiency, depending upon the specific source. The control efficiency achieved by “wet dust suppression” depends upon the design of the program – the specific suppressant and binder, the application rate, the application frequency, the condition and characteristics of the surface to be controlled. These details should have been included in the BACT analysis, together with an estimated control efficiency to satisfy Step 3 of the BACT analysis.

IV. THE DRAFT PERMIT DOES NOT ADEQUATELY LIMIT TAYLORVILLE’S POTENTIAL TO EMIT HAZARDOUS AIR POLLUTANTS TO LESS THAN MAJOR SOURCE EMISSION THRESHOLDS.

In the draft permit, IEPA has found that the Taylorville facility is a minor source of Hazardous Air Pollutants (“HAPs”), thus attempting to exempt this facility from a maximum achievable control technology (“MACT”) emission limitations. There are two types of minor sources: (1) “genuine minor source” is one in which the potential to emit is below the major source threshold; (2) a “synthetic minor” source is one with potential emissions in excess of major source emission thresholds except that enforceable limitations on the source’s potential to emit are imposed to keep the source from emitting at or above major source emission thresholds. As shown below, the draft permit violates the fundamental principles regarding the creation of minor permits, including synthetic minors, as the actual potential to emit exceeds the major source threshold and there are no permit conditions that will ensure that emissions of hazardous air pollutants from this facility will remain under major source thresholds.

Since this facility unquestionably has the potential to emit HAPs in excess of major source HAP emission thresholds and the permit does not have enforceable limitations on the potential to emit that would ensure emissions remain below this threshold, IEPA cannot authorize construction of the Taylorville facility without issuing a MACT/NESHAP determination.

A. BACKGROUND ON THE REGULATION OF HAZARDOUS AIR POLLUTANTS

The Clean Air Act reserves its strictest controls for hazardous air pollutants– air toxics posing serious health effects (often carcinogenic or neurotoxic) even in relatively small

³²³ Idaho Department of Environmental Quality, Final Permit to Construct No. P-2008.0066, Southeast Idaho Energy, LLC, pdf 54, 67; available at http://www.deq.state.id.us/AIR/permits_forms/ptc_final/se_idaho_energy_power_county_ptc_0209_statement_part_1.pdf, attached as Ex. 106.

quantities. *See* 42 U.S.C. § 7412(b)(1)-(2) (listing hazardous pollutants and instructing U.S. EPA (hereafter referred to as “EPA”) to add additional substances “reasonably anticipated to be carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive dysfunction, or which are acutely or chronically toxic.”). The regulatory regime controlling hazardous air pollutants (contained in Section 112 of the Act) reflects the enormity of those pollutants’ health effects. *See* S. Rep. No. 101-228, at 127 (1989), *as reprinted in* 1989 U.S.C.C.A.N. 3385, 3513-14 (noting that “ample margin of safety” might require “zero exposure to carcinogens, because any amount of exposure may cause a cancer”). It also reflects Congress’ frustration with state and federal agencies’ persistent failures to properly regulate air toxics; Congress described past regulatory efforts as a “record of false starts and failed opportunities.” *Id.* at 3517.

As a consequence of those congressional concerns, *id.* at 3517, Section 112 of the Clean Air Act bears three distinguishing features: (1) extraordinarily strict limits, set by the federal EPA; (2) direct, mandatory prohibitions that leave no room to avoid those limits; and, (3) express federal jurisdiction to address violations of those limits and prohibitions. *See id.* at 3513 (noting Congress’ intent to “entirely restructure the existing law, so that toxics might be adequately regulated by the Federal Government”).

The limits prescribed for hazardous air pollutants are those reflecting the “maximum achievable control technology” (“MACT”), defined as the “maximum degree of reduction in emissions.... that the Administrator [of the federal EPA] determines is achievable,” considering costs, non-air quality health and environmental impacts, and energy requirements. 42 U.S.C. § 7412(d)(2). EPA sets MACT limits for categories of industrial facilities³²⁴; once set, they apply nation-wide to all major sources within those categories. 42 U.S.C. § 7412(d)(1). *See, e.g.*, 74 Fed. Reg. 21,136, 21,140-41 (May 6, 2009) (setting standards for portland cement manufacturing facilities). On December 21, 2011, U.S. EPA set nationwide MACT limits for new and existing coal- and oil-fired electric generating units.³²⁵

Unlike other similar limits in the Act, Congress added a “floor” to the MACT definition: MACT limits for new plants may “not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined [EPA].” 42 U.S.C. 7412(d)(3).³²⁶ That floor is the heart of the MACT limit, resulting in standards that are substantially stricter than those the Act requires elsewhere. *See* 59 Fed. Reg. 15,504, 15,564 (May 10, 1994) (“[T]he MACT floor is a fundamental requirement of the section 112(g) determination.”).

For example, the “best available control technology” limits applicable to other regulated pollutants allow individual sources to plead excessive costs, or infeasibility, and thereby secure

³²⁴ These MACT limits for categories of industrial facilities are often referred to as National Emission Standards for Hazardous Air Pollutants or “NESHAPs.”

³²⁵ *See* National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units (“Final Utility MACT Rule”), available at <http://www.epa.gov/airquality/powerplanttoxics/pdfs/20111216MATSFfinal.pdf>, attached as Exhibit 107.

³²⁶ MACT limits for existing sources have a slightly relaxed floor; they may not be less stringent than the “best performing 12 percent of the existing sources.” 42 U.S.C. § 7412(d)(3)(A).

relaxed standards. 42 U.S.C. § 7479(3). The MACT floor, in contrast, applies regardless of cost, or even a particular plant's ability to meet the resulting standard. *Natural Res. Def. Council v. E.P.A.*, 489 F.3d 1364, 1376 (D.C. Cir. 2007) (“[C]ost is not a factor that EPA may permissibly consider in setting the MACT floor.”); *Cement Kiln Recycling Coal. v. E.P.A.*, 255 F.3d 855, 866 (D.C. Cir. 2001) (rejecting MACT floor based upon sources' ability to achieve limits). And MACT limits are required for every hazardous air pollutant emitted by a facility. 42 U.S.C. § 7412(a)(6); *Nat. Lime Ass'n v. E.P.A.*, 233 F.3d 625, 633-34, 640 (D.C. Cir. 2000) (noting “clear statutory obligation to set emissions for each listed [hazardous air pollutant]” and suggesting that Section 112 “does not provide for exceptions from emissions standards based on *de minimis* principles where a floor exists”).

Mindful of agencies' reluctance to impose restrictions that might be “potentially very costly for some [regulated industries],” 1989 U.S.C.C.A.N. at 3517, Congress gave the federal EPA, rather than states, the authority and obligation to set nation-wide MACT standards for major sources of hazardous air pollutants. 42 U.S.C. § 7412(e). Congress further pre-empted state authority to set “any emission standard or limitation which is less stringent than” the standards required by Section 112. 42 U.S.C. § 7416.

Under Clean Air Act Section 112(g), “no person may construct or reconstruct any major source of hazardous air pollutants, unless [EPA] (or the State) determines that the [MACT] emission limitation . . . for new sources will be met.” 42 U.S.C. § 7412(g)(2)(B) (emphasis added). *See* 40 C.F.R. § 63.42(c). Accordingly, the first step in the section 112 process is to determine whether a facility is a “major” or “minor” source of hazardous air pollutants.

A major source of HAPs is defined as a stationary source or group of stationary sources located in a contiguous area and under common ownership and control which have the potential to emit at least 10 tons per year (“tpy”) of any single HAP or at least 25 tpy of all HAPs in total. *See* IL ST CH 415 § 5/39.5; *see also* 40 C.F.R. § 63.41.

“Potential to emit” is defined as:

the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by USEPA.

See IL ST CH 415 § 5/39.5; *see also* 40 C.F.R. §§ 63.2, 63.41.

IEPA has proposed to issue a permit for the Taylorville facility that does not regulate HAP emissions because it claims that this facility is either a genuine minor source because the Taylorville facility's potential to emit HAPs is below the major source threshold or it is a synthetic minor source because permit conditions would limit its HAP emissions to less than major source HAP emission thresholds. However, the administrative record and draft Permit do not support these claims.

B. LEGAL REQUIREMENTS FOR RESTRICTING A SOURCE'S POTENTIAL TO EMIT TO LESS THAN A MAJOR SOURCE LEVEL

The definition of “potential to emit” requires first that “potential to emit” reflect the maximum capacity to emit a pollutant. Second, it requires that, to the extent that the applicant or agency claims that maximum capacity to emit is constrained in any way, the permit must explicitly set forth the constraint as a physical or operational limit – *e.g.*, a specific limit on fuel, hours of operation, or pollution control equipment operating parameters – that is federally and practically enforceable.

The definition of potential to emit in 40 C.F.R. Part 63 (which is the same definition in Illinois law, IL ST CH 415 § 5/39.5) is virtually identical to the definition of potential to emit in the PSD regulations at 40 C.F.R. § 52.21(b)(4). Courts have interpreted the definition of potential to emit in 40 C.F.R. § 52.21(b)(4) to require restrictions on operating hours or production levels or types of material combusted, rather than simply imposing limits on tons of pollutants emitted per year. *See United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1122, 1133 (D. Colo. 1987) (blanket restrictions on actual emissions cannot be considered in determining potential to emit because these blanket emission restrictions, unlike limitations on hours of operation, fuel consumption, or production, “would be virtually impossible to verify or enforce.”)

Courts have emphasized the need to ensure that any constraints assumed on potential to emit are grounded in enforcement reality. *See United States v. Louisiana Pacific Corp.*, 682 F. Supp. 1122 (D. Colo. 1987); *Weiler v. Chatham Forest Products*, 392 F. Supp. 532, 535 (2d Cir. 2004) (“In short, then, a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels”).

Shortly after the *Louisiana-Pacific* decision discussed above, the U.S. EPA issued policy on limiting potential to emit on June 13, 1989.³²⁷ In this final guidance, U.S. EPA specified requirements for properly limiting potential to emit. U.S. EPA made it clear that, to be federally enforceable, limitations must be enforceable as a practical matter. U.S. EPA stated that proper limits on potential to emit must include a production or operational limitation in addition to an emission limitation “where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment.”³²⁸ Restrictions on production or operation would include limitations on amount of fuel combusted, hours of operation, or conditions which require the source to install and operate air pollution control technology to a specified emission rate or specified efficiency level. EPA stated that there are two exceptions to the prohibition on using blanket emission restrictions to limit potential to emit. One exception pertained to surface coating operations, and the other exemption applies when

³²⁷ EPA Memorandum from Terrell E. Hunt to John S. Seitz with subject “Guidance on Limiting Potential to Emit in New Source Permitting” (June 13, 1989), attached as Ex. 107.

³²⁸ *Id.* at 5-6.

setting operating parameters for control equipment is infeasible. In such cases, a permit that includes “short term emission limits (*e.g.*, lbs per hour) would be sufficient to limit potential to emit, provided that such limits reflect the operation of the control equipment, and the permit includes requirements to install, maintain, and operate continuous emission monitoring (“CEM”) system and to retain CEM data, and specifies that one can use the CEM data to determine compliance with emission limit.”³²⁹

U.S. EPA’s 1989 guidance document also discussed “sham operation permits.” Specifically, U.S. EPA stated “permits with conditions that do not reflect a source’s planned mode of operation are void *ab initio* and cannot act to shield the source from the requirement to undergo preconstruction review.”³³⁰

Subsequent to the 1989 policies, U.S. EPA issued a policy in January 1995 that discussed the various mechanisms available to create federally enforceable emission limitations on HAP emissions.³³¹ Permitting programs approved under the SIP can only impart federal enforceability with respect to criteria pollutant emission limits. To create federally enforceable emission limitations for HAPs, the permitting program must be approved under Section 112(l) of the Clean Air Act. U.S. EPA’s January 25, 1995 guidance elaborated on prior policies including EPA’s June 13, 1989 guidance on creating federally and practically enforceable limitations on potential to emit. These policies are still relied on today for determining whether permit conditions effectively limit potential to emit. *See, e.g.*, U.S. EPA Objection to Proposed Title V Permit for Quebecor World Franklin located in Franklin, Kentucky (Aug. 29, 2002); *see also United States v. Questar Gas Mgmt. Co.*, 2:08-CV-167 TS, 2011 WL 1793172 (D. Utah 2011) (“the Court finds that, as it relates to the NESHAP regulations [HAP regulations], limitations on a facility's emissions may only be considered when they are legally and practicably enforceable by a governmental entity”).

The state of Illinois developed a state operating permit program to, among other things, create federally enforceable limits on potential to emit. U.S. EPA approved that program as part of the Illinois state implementation plan (commonly referred to as the “SIP”) and under Section 112 of the Clean Air Act on March 7, 1995. 60 Fed. Reg. 12,478 (March 7, 1995). In that approval, EPA reiterated the criteria of its July 28, 1989 Federal Register notice that permit limitations must create federally enforceable limitations on potential to emit. EPA explicitly stated, it was “promulgating approval of Illinois’ federally enforceable state operating permit program (FESOP) for the purposes of creating federally enforceable limitations on the potential to emit of Hazardous Air Pollutants (HAP) regulated under section 112 of the CAA. The EPA is approving this program as meeting the criteria articulated in the June 28, 1989, Federal Register notice for State operating permit programs to establish limits federally enforceable on potential to emit and the criteria established in section 112(l).” 60 Fed. Reg. 12,482; *see also* 35 Ill. Adm.

³²⁹ *Id.* at 8.

³³⁰ *Id.* at 12.

³³¹ Memorandum from Kathie A. Stein to the EPA Regional Air Division Directors with Subject “Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits.”, attached as Ex. 108.

Code 211.2270, 35 Ill. Adm. Code 211.4970. IEPA has proposed to issue the permit for the Taylorville facility pursuant to its state FESOP program.

C. THE TAYLORVILLE FACILITY IS NOT A GENUINE MINOR SOURCE AS THIS FACILITY HAS THE POTENTIAL TO EMIT OVER 10 TONS PER YEAR OF A SINGLE HAP OR AT LEAST 25 TONS PER YEAR OF ALL HAPS IN TOTAL

The Taylorville Energy Center would operate equipment that would have the potential to emit HAPs. Emission points include the flare, thermal oxidizer (“TO”) for the sulfur recovery unit (“SRU”), and acid gas reduction (“AGR”) unit vent in the gasification block; the exhaust stack serving the combined cycle combustion turbines (“CCCTs”) and heat recovery steam generator (“HRSG”) in the power block; the natural gas-fired burners in the coal milling and drying system; the gasifier coal bunker vents; the natural gas-fired auxiliary boiler and startup heater; the diesel-fueled fire pump and emergency generator engines; the methanol and diesel storage tanks; and fugitive equipment leaks.³³²

The IEPA finds that the proposed plant would not be a major source of HAPs because potential emissions from these emission points would be less than the applicable thresholds of 25 tons per year in the aggregate for total HAPs and less than 10 tons per year for any single HAP.³³³ Accordingly, the IEPA finds that the plant is not subject to the National Emission Standards for Hazardous Air Pollutants (“NESHAPs”), adopted by U.S. EPA under 40 CFR 63, that apply to major sources of HAPs.³³⁴ The IEPA finds further that a case-by-case determination of maximum achievable control technology (“MACT”) pursuant to Section 112(g) of the Clean Air Act is not needed for those emission units at the facility that would not be subject to the NESHAP standards.³³⁵

As demonstrated below, IEPA’s conclusions are erroneous and based on severely flawed and not adequately supported emission estimates for HAPs. The Draft Permit then compounds these errors by failing to reflect the emission calculations in enforceable permit limits. When properly estimated, potential emissions of HAPs from the proposed facility by far exceed the major source thresholds for both single and total HAPs, making the proposed facility a major stationary source of HAPs and requiring MACT for all applicable sources.

1. Potential to Emit Estimates for HAPs are Not Adequately Supported.

The IEPA does not provide a discussion of HAP emission estimates in its Permit Summary for the facility and appears to have accepted the Applicant’s emission estimates wholesale. Many of the Applicant’s emission estimates for HAPs rely on emission factors from emission testing at other facilities, vendor-supplied information, or other studies that were not

³³² Ap., pp. 12-2 through 12-4.

³³³ Permit Summary, p. 20; Draft Permit, p. 3.

³³⁴ *Ibid.*

³³⁵ *Ibid.*

made available for public review. Thus, a considerable portion of the Applicant's emission estimates for HAPs are unsupported in the Permit record. The following information, used by the Applicant to develop emission estimates for the facility, was not made available:

- The metallic HAP content of coal, used to determine the raw and sweet syngas combustion emission factors for the flare and AGR and the SNG combustion emission factor for the CCCTs, flare, methanation startup heater, SRU thermal oxidizer, auxiliary heater and boiler was allegedly based on metals sampling data for Herrin Illinois coal provided by the Illinois State Geological Survey (“ISGS”).³³⁶ This dataset is not provided. Instead, the Application provides an inactive weblink to the ISGS coal quality database.³³⁷ Further, the Application provides no discussion whatsoever why the HAP content of Herrin Illinois coal is deemed representative for the coal that Tenaska would gasify at Taylorville as the Draft Permit does not contain any conditions limiting the facility to Herrin Illinois coal. (*See* discussion *supra* regarding the enforceability comment on coal origin.)
- The metallic HAP conversion rate for coal-to-raw syngas, used to determine combustion emission factors for syngas, was allegedly based on a “pilot scale test of Illinois coal to raw syngas ... performed by gasifier vendor for all metals except mercury.”³³⁸ This pilot-scale test performed by the gasifier vendor was not provided for review.
- The removal rate of the carbon absorption beds for mercury (90%) used to determine emission factors for syngas and SNG, was allegedly based on the “design removal efficiency.”³³⁹ The record contains no information on the vendor of the carbon absorption beds, design specification sheets, or other any other information that would support a design removal rate of 90%.
- The removal efficiency of the syngas conditioning train for hydrogen fluoride (99%), used to determine hydrogen fluoride combustion emission factors for syngas and SNG, was allegedly “predicted by heat and material balance data for fluorides.”³⁴⁰ These heat and material balances were not provided in the record.
- The non-metallic HAP combustion emission factors for syngas, used to determine emissions from the flare and AGR, were allegedly based on field data collected at the Louisiana Gasification Technologies Incorporated (“LGTI”) facility in November 1995 as presented in the October 16, 1996 *Summary Report: Trace Substance Emissions from a Coal-Fired Gasification Plant* prepared by Radian International,

³³⁶ See Ap., Footnote A to Appx. C, Table C-22-2.

³³⁷ *Id.*

³³⁸ See Ap., Footnote B to Appx. C, Table C-22-2.

³³⁹ See Ap., Footnote C to Appx. C, Table C-22-2.

³⁴⁰ See Ap., Footnote C to Appx. C, Table C-22-2.

LLC for the Electric Power Research Institute (“EPRI”) and the U.S. Department of Energy (“DoE”).”³⁴¹ This report was not provided in the record.

We submitted a public records request to IEPA asking for all information related to the Draft Permit but were not provided with any of the above information.

In *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, PSD Appeal Nos. 99-4 & 99-5, 2000 WL 833062 (June 22, 2000), the Environmental Appeals Board remanded the permit back to the state agency after finding that the state agency’s PTE evaluation was inadequate because the agency did not include explanations of the underlying basis for its calculations and the public record contained no documents supporting its conclusion. Without this information, the Board determined that it was unable to determine whether or not the significance level for a given pollutant would be exceeded and, thus, whether BACT for lead should be installed at this facility. Moreover, the Board remanded the permit back to the state agency because it failed to consider detailed comments regarding an alternative calculation for potential to emit submitted by a commenter. The comments had articulated how the agency had underestimated the facility’s emissions of lead and other hazardous air pollutants, erroneously failed to consider all potential sources of lead emissions, and finally presented its own calculated PTE after correcting for these deficiencies.

This draft Permit is similar to the Steel Dynamics permit as IEPA’s potential to emit evaluation for HAPs is inadequate, cursory, and not supported by documents in the record. Moreover, Sierra Club and Natural Resources Defense Council describe in detail below how the agency underestimated these impacts and provide our own calculated potential to emit for HAPs after correcting for these deficiencies.

2. Emission Calculations are Arbitrary and Substantially Underestimate Potential HAP Emissions.

The IEPA does not appear to have conducted independent emission calculations for the proposed Taylorville; instead, it appears to have relied entirely on the Applicant’s estimates of potential HAP emissions contained in the Application, Appendix C, to come to its conclusion that the facility is not a major source of HAPs. We requested from IEPA a copy of the 111 pages of spreadsheets contained in Appendix C in their native Excel format. Apparently, IEPA is not in possession of the requested information. This casts serious doubt on the thoroughness of IEPA’s review of the Applicant’s emission calculations as it is exceedingly difficult and time-consuming to wade through 111 pages of spreadsheets in PDF format and understand not only how these spreadsheets are linked to each other but also how individual emission factors were derived and emissions were calculated. We spent dozens of hours “re-engineering” these spreadsheets to understand the Applicant’s emission calculations. Based on our review, and as discussed below, the Applicant’s derivation of HAP emission factors is arbitrary and not adequately supported. As a result, the resulting estimates of potential HAP emissions are erroneous and fail to establish the Taylorville facility is a genuine minor source of HAPs. Further, as discussed supra, the permit

³⁴¹ See Ap., Footnote 1 to Appx. C, Table C-22-3.

limits established based on these unsupported emission estimates are unenforceable as a practical matter and thus do not assure that minor source status is actually achieved and maintained.

a. Revised HAP Emissions

As discussed previously, the emission estimates provided by the Applicant substantially underestimate HAP emissions from fugitive equipment leaks. We calculated the impact of equipment leak emission factor selection on the HAP emission inventory. This analysis, included in Exhibit 19, indicates that total HAP emissions would increase from 19.24 ton/yr³⁴² to 25.91 ton/yr if the “with ethylene” SOCFI factor were used and to 29.2 ton/yr if EPA’s average refinery emission factors were used. This increase is due to increases in emissions of methanol and COS. The total HAP emissions would be even higher if other errors in the HAP emission calculations, discussed in Section II.D, were corrected.

Thus, selection of emission factors alone determines the HAP major source status of this facility. As no monitoring at all is required to confirm that the assumptions used to estimate equipment leak emissions are actually met, the most conservative estimate of emissions should be used to determine HAP major source status.

b. Methanol Emissions Are Underestimated

The Taylorville facility would operate a Rectisol®-based acid gas removal unit to selectively separate sulfur compounds and CO₂ from the syngas. The Rectisol® absorber will utilize chilled methanol as a physical solvent. A 903,370-gallon storage tank with an annual turnover of 2,030,000 gallons per year (“gal/year”) would supply makeup methanol to the AGR.³⁴³ Based on a density of 6.6 lb/gal for methanol, the annual turnover of methanol can thus be calculated at 6,699 ton/yr.³⁴⁴

Although the Draft Permit quantifies the maximum annual makeup (turnover) of methanol, the losses of methanol permitted by the Draft Permit and quantified by the underlying Application do not total 6,699 ton/yr. Emissions of methanol are identified in Appendix C to the Application and were easily totaled. Some of the methanol that is lost is combusted (and converted to CO₂ and water). Other emissions occur via fugitive sources, where the methanol is directly emitted to the atmosphere through evaporation and leaks. Both types of losses are accounted for in the Application from six sources, specifically, the methanol tank, flare, sulfur recovery unit, acid gas removal unit, gasifier process area, and fugitive equipment leaks. The following summarizes uncontrolled losses of methanol from each of these sources.

Methanol tank: Because losses from the methanol tank as VOM consist entirely of methanol, which is a HAP, all fugitive losses from the methanol tank must be accounted for in the HAP emission estimates. The Application, Appendix C, estimates 0.11 ton/yr fugitive losses

³⁴² Ap., v. 1, Appx. C, p. C-87, Table C-23.

³⁴³ Ap., pp. 2-10, 2-14, and 10-1 and Draft Permit, Cond. 4.8.5.b.

³⁴⁴ (2,030,000 gal/year) × (6.6 lb methanol/gal) × (1 ton/2,000 lb) = 6,699 tons methanol/year.

for an internal floating roof tank with the U.S. EPA's TANKS model.³⁴⁵ Tank emission factors calculated by the EPA Model assume that the floating tank roof is always floating and thus does not include roof landing losses. However, when the floating roof is landed, large amounts of VOCs are expelled. The Applicant recognized that these losses were not included in the Application's emission estimates for the methanol tank and submitted a supplemental calculation for tank landing emissions.³⁴⁶ The total losses of methanol during roof landing, which consist of standing idle losses and filling losses, were estimated at 0.097 ton/yr.³⁴⁷ Thus, total losses from the methanol tank can be estimated at 0.21 ton/yr. The Draft Permit, Condition 4.8.6 permits total emissions of methanol from the methanol tank of 0.25 ton/yr including roof landing losses, 0.4 ton/yr more than estimated by the Applicant. IEPA does not provide an explanation for this discrepancy.

Flare: The Application estimates pre-flare (uncontrolled) emissions during a flare cold plant startup at 2.57 ton/yr. Uncontrolled emissions during total plant shutdown are estimated at 0.28 ton/yr.³⁴⁸ Thus, uncontrolled emissions from the flare total 2.85 ton/yr.

Sulfur recovery unit: The Application estimates controlled methanol emissions from the sulfur recovery unit thermal oxidizer during plant cold startups at 8.61E-04 ton/yr and a control efficiency for methanol of the thermal oxidizer of 99%.³⁴⁹ Based on this information, uncontrolled losses of methanol routed to the thermal oxidizer can be calculated at 0.09 ton/yr.³⁵⁰

Acid gas removal unit: The Applicant provided an estimate for total controlled emissions from the AGR CO₂ vent stream during normal operations of 2.63 ton/yr and of 0.05 ton/yr during cold startups.³⁵¹ Thus, controlled emissions of methanol from the AGR unit total 2.68 ton/yr.

The CO₂ product vent stream from the AGR train will be routed to a dedicated thermal oxidizer.³⁵² Based on the control efficiency of this thermal oxidizer, 90%, uncontrolled losses of methanol attributable to the AGR process area can be estimated at 26.8 ton/yr.³⁵³

Gasifier coal bunker vent: The Application estimates a total of 0.3 ton/yr of methanol losses through the gasifier coal bunker vent.³⁵⁴

³⁴⁵ Ap., Appx. C, Table C-18.1, pp. C-63 - C-64.

³⁴⁶ Email from Larry Carlson, Tenaska, to Chris Romaine and Robert Smet, September 15, 2011, Attachment: MEOH Tank Landing Emissions Calculations v.1.0.pdf (provided by IEPA in response to FOIA request), attached as Ex. 109.

³⁴⁷ $(194.8 \text{ lb/event}) \times (1 \text{ event/year}) \times (1 \text{ ton}/2000 \text{ lb}) = 0.097 \text{ ton/yr.}$

³⁴⁸ Ap., Appx. C, Tables C-3.3 and C-3.4, p. C-11.

³⁴⁹ Ap., Appx. C, Table C-4.4, p., C-23, and C-22.

³⁵⁰ $(8.61\text{E-}04 \text{ ton/yr}) \times (100/1) = 8.61\text{E-}02 \text{ ton/yr.}$

³⁵¹ Ap., Appx. C, pp. C-26 to C-27 and p. C-30 and Table C-5.4, p. C-30.

³⁵² Ap., Appx. C, pp. C-26 to C-27.

³⁵³ $(2.68 \text{ ton/yr}) \times (100/10) = 26.8 \text{ ton/yr.}$

³⁵⁴ Ap., Appx. C, p. C-43.

Fugitive equipment leaks: The Application provides estimates of uncontrolled methanol losses from the hundreds of individual components including valves, pumps, compressors, PRVs, connectors, open ended lines, and sample connectors in the various process areas of the plant including the gasification/syngas conditioning area (6.63E-03 ton/yr), the AGR process area (1.73E-02 ton/yr), the SRU process area (3.6E-03 ton/yr), and miscellaneous other process areas (6.83E-02 ton/yr).³⁵⁵ These fugitive emissions add up to a total of 0.16 ton/yr of methanol losses. Elsewhere, the Application estimates a total of 1.0 ton/yr of methanol emissions from fugitive equipment leaks.³⁵⁶

Total methanol losses: Table 16 below summarizes uncontrolled and controlled emissions from the above discussed six sources and respective permit conditions, where applicable.

Table 16
Methanol emissions quantified by the Application
and permit limits set by the Draft Permit

Emission source	Uncontrolled Emissions ^a (ton/yr)	Controlled Emissions ^b (ton/yr)	Permit Limit (ton/yr)
Methanol tank	0.25 ^c	0.11	0.11 (Cond. 4.8.2.b) ^d 0.25 (Cond. 4.8.6) ^e
Flare	2.85	2.85E-02	
AGR	26.8	2.68	2.68 (Cond 4.1.6)
SRU	0.09	8.61E-04	
Gasifier coal bunker vent	0.30	0.30	
Equipment leak fugitives	1.00	1.00	1.05 (Cond. 4.9.5)
Total facility-wide	31.29	4.12	

a see discussion above

b Ap., Appx. C, Table C-23.1 "Plant-wide HAP/TAP emissions summary"

c based on Draft Permit Condition 4.86

d limit set for methanol emissions as VOM, excluding roof landing losses

e limit set as methanol emissions as VOM, including roof landing losses

As Table 16 shows, the Application accounts for a total loss of 31.29 ton/yr of methanol from the six identified sources. When comparing these annual facility-wide emissions with the annual methanol makeup, there is a discrepancy of 6,668 ton/yr (the difference between the amounts of methanol added to the tank every year (6,699 ton/yr) minus the amounts identified as lost (30.56 ton/yr). Because the identified losses amount to less than 0.5% of the amount of methanol make-up,³⁵⁷ it is clear that there is some other unidentified source(s) of methanol losses.

If this amount of methanol were directly emitted somewhere in the facility, it would constitute an enormous additional emission source. As discussed elsewhere in this comment letter, the Applicant substantially underestimated fugitive equipment leaks, which explains some

³⁵⁵ Ap., Appx. C, pp. C-104 to C-110.

³⁵⁶ Ap., Appx. C, Table C-23.1, p. C-87.

³⁵⁷ (31.29 ton/yr) / (6,699 ton/yr) = 0.0047.

of the unaccounted-for methanol losses. However, even if the entire unaccounted-for quantity of methanol of 6,668 ton/yr were burned and sent up a stack with 99% combustion efficiency, emissions would still amount to about 67 ton/yr.³⁵⁸ Thus, even under the best-case scenario, the unaccounted-for emissions of methanol render the facility a major source of HAPs.

c. HAP Emissions from Power Block Are Underestimated.

The power block at Taylorville Energy Center would consist of two CCCTs and a single heat recovery steam generator which will not be equipped with duct burners. The operator would fire the CCCTs with either SNG from the gasification block or pipeline natural gas.³⁵⁹ To estimate HAP emissions from the CCCTs, the Application developed HAP emission factors for combustion of SNG and natural gas for both normal operations and startup/shutdown of the CCCTs. As discussed below, the Applicant's approach to developing HAP emission factors is problematic and substantially underestimates potential HAP emissions from the power block. In fact, HAP emissions from the power block alone would be high enough to qualify the facility as a major source of HAPs.

i. *Synthetic Natural Gas Is Not Guaranteed to Have the Same Combustion Characteristics as Natural Gas*

The Applicant derived emission factors for 1,3-butadiene, acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, naphthalene, polyaromatic hydrocarbons ("PAH"), propylene oxide, toluene, and xylenes based on U.S. EPA's *Compilation of Air Pollution Emission Factors* ("AP-42"), Chapter 3.1, Stationary Gas Turbines, for uncontrolled natural gas-fired turbines. All other organic HAP emission factors were based on AP-42, Chapter 1.4 for External Natural Gas Combustion.³⁶⁰

Neither the Applicant nor the IEPA provides a satisfactory explanation why emission factors derived for natural gas-fired combustion sources (and especially for heaters and boilers) are considered applicable to combustion of SNG in the CCCTs at the proposed Taylorville facility. In its engineering evaluation, the IEPA provides several definitions for natural gas based on 40 CFR 60.41Da, 40 CFR 60.41b, 40 CFR 60.41c, 40 CFR §60.331(u), 40 CFR §60.4420, and 40 CFR §72.2.³⁶¹ Despite the fact that every one of these definitions defines "natural gas" as a "naturally occurring" mixture of hydrocarbons, the IEPA finds that it considers SNG equivalent to natural gas because it will meet the most stringent physical and chemical specification of any of these definitions including a higher heating value between 950 and 1,100 British thermal units per standard cubic foot ("Btu/scf") and a maximum fuel sulfur content of 0.5 grains of total sulfur per 100 scf. In addition, IEPA finds that SNG has much higher methane purity than pipeline natural gas and does not contain any longer chain hydrocarbons that are either directly emitted post-combustion as VOM or form VOM through

³⁵⁸ $(6,668 \text{ ton/yr}) \times (1-0.99) = 66.68 \text{ ton/yr}$.

³⁵⁹ Draft Permit, Cond. 4.2.1.

³⁶⁰ Ap., p. 12-3 and Appx. C, Table C-23, p. C-88.

³⁶¹ Permit Summary, p. 3-8.

secondary reactions. Since the SNG produced by the Taylorville facility meets all physical and chemical specifications of natural gas and, with respect to “some” regulated air pollutants, is expected to produce less combustion byproduct emissions than natural gas, IEPA finds that it is appropriate to use natural gas emission factors for all SNG combustion at the facility.³⁶² These arguments are not convincing.

First, while the produced SNG may have similar physical and chemical characteristics compared to pipeline natural gas, the two gases are just that: similar, but not identical. SNG may have a similar heat content, maximum sulfur fuel content, and higher methane content as natural gas but may have a different content of other components that affect the combustion process and the formation of pollutants.

Second, the Draft Permit does not contain a requirement that SNG be consistently produced to the specifications assumed by IEPA. For example, while the Draft Permit requires sampling and analysis of the sulfur content (including total sulfur, H₂S, COS, and CS₂), chlorine, fluorine, metals, VOM and methanol, it does not require testing for methane, hydrogen, carbon monoxide or moisture content or the higher heating value of the SNG, all of which affect the combustion process and the formation of combustion products including HAPs.³⁶³

ii. *CO Ratio Scaling Approach Is Not Supported.*

Rather than using the emission factors provided in AP-42, Chapter 3.1, as given, the Applicant scaled each emission factor by “the ratio of the uncontrolled CO emission factor for diffusion flame combustion turbines to the lean premix CO emission factor to reflect the greater combustion control and resulting lower organic HAP emissions that are expected from lean premix combustion turbines.”³⁶⁴ The following formula illustrates the Applicant’s ratio calculation:

$$EF_{\text{HAP Draft Permit}} = (EF_{\text{HAP AP-42, Ch. 3.1}}) \times (EF_{\text{CO Draft Permit}}) / (EF_{\text{CO AP-42, Ch. 3.1}}) \text{ where}$$

$EF_{\text{HAP Draft Permit}}$ = emission factor for HAP used in Draft Permit

$EF_{\text{HAP AP-42, Ch. 3.1}}$ = average emission factor for HAP from AP-42, Chapter 3.1, for uncontrolled natural gas-fired turbines at high load (>80%)

$EF_{\text{CO Draft Permit}}$ = emission factor for CO at full load (0.0094 lb/MMBtu)

$EF_{\text{CO AP-42, Ch. 3.1}}$ = average emission factor for CO from AP-42, Chapter 3.1, for uncontrolled natural gas-fired turbines at high load (>80%) (0.082 lb/MMBtu)

³⁶² Permit Summary, p. 3-9.

³⁶³ See Draft Permit, Cond. 4.2.7.

³⁶⁴ Ap., p. 12-3, and Appx. C, Footnote A to Table C-23, p. C-91.

Based on this ratio calculation, the emission factors used in the Draft Permit to estimate potential HAP emissions from the Taylorville facility burning SNG amount to only 11.5% of the emission factors for combustion of natural gas provided by AP-42, Chapter 3.1.³⁶⁵ Neither the Application nor the Permit Summary provides any explanation or justification for using this ratio. There are a number of problems with this approach.

First, the Applicant supplies no support whatsoever for the CO emission factor of 0.0094 pounds per million British thermal units (“lb/MMBtu”) for full load, which was used to scale the AP-42 HAP emission factors for uncontrolled turbines at high load (>80%). Allegedly, this CO emission factor has been provided by the CCCT vendor³⁶⁶ but neither the Applicant nor IEPA provide a vendor guarantee or a demonstration of this emission factor.

Second, the U.S. EPA in AP-42, Chapter 3.1 for stationary gas turbines explicitly points out that “[i]t is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.”³⁶⁷ For this reason alone, the use of the CO ratio scaling approach as used by the Applicant is not justified.

Third, it is well known that, similar to CO emissions, HAP emissions increase with reduced operating loads. Turbines are designed to run efficiently at full load where fuel combustion is nearly 100 percent efficient. At lower loads, and during startup, turbines are extremely inefficient,³⁶⁸ which results in incomplete combustion.³⁶⁹ This increases products of incomplete combustion, such as carbon monoxide (“CO”), aldehydes, and hydrocarbons.³⁷⁰ However, the relationship is not necessarily directly proportional and differs for individual HAPs as well as with the type of turbine. Neither the Applicant nor the IEPA provide a demonstration that emissions of individual HAPs increase or decrease at a 1:1 ratio with CO emissions at different loads.

Based on the average emission factor for formaldehyde provided in U.S. EPA’s AP-42, Chapter 3.1 (without scaling), emissions from the two turbines during normal operations alone (8,528 hours/year without even accounting for startup and shutdown emissions), can be calculated at 13.6 ton/yr.³⁷¹ Thus, when relying on the average emission factor given in AP-42,

³⁶⁵ $(0.0094 \text{ lb/MMBtu}) / (0.082 \text{ lb/MMBtu}) = 0.115$.

³⁶⁶ Ap., Appx. C, Footnote 2 to Table C-8.1, p. C-34.

³⁶⁷ AP-42, Chapter 3.1, Footnote c to Table 3.1-1.

³⁶⁸ R. H. Kehlhofer, J. Warner, H. Nielsen, and R. Bachmann, Combined-Cycle Gas Steam Turbine Power Plants, 2nd Ed., PennWell, Tulsa, OK, 1999, Chapter 8: Operating and Part Load Behavior.

³⁶⁹ A. H. Lefebvre, Gas Turbine Combustion, 2nd Ed., Taylor & Francis, Philadelphia, PA, 1998, Sec. 9-4, Mechanisms of Pollutant Formation.

³⁷⁰ Gas Research Institute (“GRI”) and Electric Power Research Institute (“EPRI”), 1996. Gas-Fired Boiler and Turbine Air Toxics Summary Report. Prepared by Carnot Technical Services for GRI and EPRI, August 1996, attached as Ex. 138.

³⁷¹ $(7.1\text{E-}04 \text{ lb formaldehyde/MMBtu}) \times (2,250 \text{ MMBtu/turbine/hr}) \times (2 \text{ turbines}) \times (8,528 \text{ hours normal operations/year}) \times (\text{ton}/2,000 \text{ lb}) = 13.62 \text{ ton formaldehyde /year}$.

formaldehyde emissions from normal operations of the turbines alone exceed the threshold for single HAPs of 10 ton/yr and render the facility a major source. Based on the (unmodified) average emission factor for toluene provided in AP-42, Chapter 3.1, toluene emissions from normal operations of the turbines account for an additional 2.5 ton/yr.³⁷²

iii. *Non-Metallic HAP Emission Factors Used By Applicant Underestimate Potential to Emit.*

Even if one accepted the Applicant's premise that SNG is equivalent to natural gas, the emission factors used by the Applicant to determine potential to emit for non-metallic HAPs (based on AP-42, Chapter 3.1) are not appropriate for estimating the "maximum capacity of a stationary source to emit any air pollutant" as required under 40 CFR §§ 63.2 and 63.41.

First, almost all of the tests evaluated for AP-42, Chapter 3.1, were conducted for compliance purposes. Compliance tests, or source tests, are typically announced and, thus, give the operator the opportunity for optimizing equipment and operating at optimal conditions. As such, measured emission rates are most likely on the lower end of what would be observed under non-optimized conditions.

Second, the *average* emission factors from AP-42 are not appropriate to determine the *maximum* HAP emissions from the facility. Either the *maximum* or the 95th percentile emission factors measured during those tests would have been more appropriate. (The U.S. EPA provides Microsoft Access databases with all test results used to develop emission factors for Chapters 3.1 and 1.4.³⁷³) In a memorandum on HAP emission factors from natural gas-fired turbines, the U.S. EPA emphasizes that "[t]he 95th upper percentile emission factor may be more appropriate to use [than the average emission factor] for determining whether a source is major since it considers the test result variability."³⁷⁴

The Environmental Appeals Board decision in *In re Peabody Western Coal Co.*, 12 E.A.D. 22, CAA Appeal No. 04-01 (Feb. 18, 2005) demonstrates why relying on emission factors is not sufficient in a potential to emit analysis. In that case, Peabody tried to establish that one of its facilities was a synthetic minor source for purposes of PSD. Peabody's request for a PTE limit of 185 ton/year relied on a quantitative estimate of the Facility's capacity to emit PM10. This estimate, in turn, relied on emission factors and assumed emission control efficiencies. Peabody estimated the uncontrolled emissions from each emissions unit based on the application of AP-42 emission factors. Peabody then estimated the net emissions from these

³⁷² $(1.3E-04 \text{ lb toluene/MMBtu}) \times (2,250 \text{ MMBtu/turbine/hr}) \times (2 \text{ turbines}) \times (8,528 \text{ hours normal operations/year}) \times (\text{ton}/2,000 \text{ lb}) = 2.49 \text{ ton toluene/year.}$

³⁷³ U.S. Environmental Protection Agency, AP 42 Section 3.1 Stationary Gas Turbines, Related Information and AP 42 Section 1.4 Natural Gas Combustion, Related Information; <http://www.epa.gov/ttn/chief/ap42/ch03/related/r03s01.zip> and <http://www.epa.gov/ttn/chief/ap42/ch01/related/r01s04.zip>.

³⁷⁴ Roy Sims, U.S. Environmental Protection Agency, to Docket A-95-51, re: Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines, April 21, 2001 (hereafter "U.S. EPA April 2011 Memorandum"); [http://www.deq.state.ms.us/mdeq.nsf/pdf/epd_EPAMemorelatedtoHAPs/\\$File/EPAMemoHAPs.pdf?OpenElement](http://www.deq.state.ms.us/mdeq.nsf/pdf/epd_EPAMemorelatedtoHAPs/$File/EPAMemoHAPs.pdf?OpenElement).

units by applying assumed control efficiencies, and requested that Region IX establish a PTE limit for the Facility based on the cumulative total estimated net emissions. Similarly, Peabody's proposed compliance regimen did not include direct measurement of PM emissions.

U.S. EPA, Region IX, however, found a fundamental conceptual difference between PTE and actual emission performance that made Peabody's complete reliance on emission factors inappropriate in this instance. "While PTE is intended to identify the highest possible level of emissions that a facility is capable of releasing in light of its physical design and operational characteristics (considering enforceable restrictions on emission capacity), emission factors are intended to provide a generalized estimate of the average emissions performance of a particular type of emission source. According to AP-42, '[i]n most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average).' As a result, according to Region IX, emission factors do not necessarily reflect the level of emission appropriate for calculating PTE." *In re Peabody Western Coal Co.*, 12 E.A.D. 22. Region IX stated that it "was not 'disputing Peabody's use of emission factors and control efficiencies for the purpose of calculating actual emissions,' but that because 'PTE is meant to be a worst case emissions calculation,' Peabody's approach was not adequate for 'the creation of a practically enforceable PTE limit for regulatory purposes.'" *Id.* The Environmental Appeals Board upheld the Region's decision that this could not be a synthetic minor source when its PTE were based on emission factors. *Id.* Similarly, Tenaska's reliance of emission factors in its potential to emit HAPs analysis is inadequate.

iv. *Hexane Emissions Are Improperly Excluded.*

The Application does not estimate emissions for hexane for either normal operation or startup/shutdown arguing that "[s]ince hexane emissions were not detected during the combustion turbine testing used to develop the AP-42 Chapter 3.1 emission factors, hexane emissions are not expected from the CCCTs at the Taylorville facility."³⁷⁵ This is a curious argument as the same logic holds true for all other pollutants for which the Application used emission factors from AP-42, Chapter 1.4 for external natural gas combustion. The Applicant had no such compunction about using AP-42 Chapter 1.3 emission factors for the pollutants acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(a)fluoranthene, benzo(g,h,i)perylene, benzo(k)fluoranthene, chrysene, dibenz(a,h)anthracene, 1,4-dichlorobenzene, 7,12-dimethylbenz(a)anthracene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, 3-methylcholanthrene, methylanthralene, or pyrene for estimating emissions from the CCCTs.³⁷⁶

In fact, the only reason the Applicant resorted to using Chapter 1.4 emission factors is because Chapter 3.2 for natural gas-fired turbines does not provide emission factors for those HAP pollutants. The only difference between the above-mentioned pollutants and hexane is the fact that Chapter 1.4 provides an emission factor for hexane that is between three and six orders of magnitude larger than the emission factors provided for the other pollutants. It is obvious that

³⁷⁵ Ap., Appx. C, Footnote D to Table C-23, p. C-91.

³⁷⁶ See, Ap., Appx. C, Table 23.2, pp. C-89 to C-91.

this exclusion argument was developed to avoid quantifying the large emissions that would result from applying the Chapter 1.4 emission factor for hexane (1.8E-03 lb/MMBtu³⁷⁷) as emissions from normal operation alone would amount to 16.9 ton/yr of hexane³⁷⁸, thereby exceeding the single source HAP threshold for a major source. This example illustrates the arbitrary and baseless approach the Applicant used to estimate emissions for the Taylorville Energy Center.

d. Hydrogen Chloride Emissions Were Omitted

During the gasification process, most of the chloride species in coal are converted to hydrogen chloride (“HCl”), which is a HAP.³⁷⁹ The actual concentration of HCl vapor in a coal gas stream will depend on the chlorine content of the coal, the gasification temperature, the type of gasifier, and the presence/concentration of alkali metals in the gasification system.³⁸⁰

The Application provides estimates for HCl emissions from the flare and from equipment leak fugitives; however, it fails to estimate emissions of HCl from sources that combust SNG, including the CCCTs, the AGR vent catalytic oxidizer, the SRU thermal oxidizer, auxiliary boiler, coal milling and drying stack, or the methanation startup heater.³⁸¹ The permit record does not provide a satisfactory explanation why HCl emissions were not quantified for these sources.

The Permit Summary admits that the syngas exiting the gasifier contains significant amounts of HCl and claims that the pollutant is removed when the raw syngas is scrubbed with water.³⁸² The Application provides that the syngas conditioning train removes approximately 99% of the chlorides contained in raw syngas yet fails to account for the 1% of chlorides that would remain in the sweet syngas.³⁸³ This remaining 1% of the chloride, if not otherwise removed, will be combusted with the cleaned sweet syngas and SNG and must therefore be accounted for in the HAP emission estimates.

The air permit application for the Kentucky NewGas SNG production facility, which was prepared by Trinity Consultants (the same consultant who prepared the application for the Taylorville facility), established separate HCl emission factors for syngas and SNG combustion based on emission factors determined from a series of stack tests conducted at the Wabash River

³⁷⁷ $(1.8E+00 \text{ lb hexane/MMscf}) / (1 \text{ MMscf}/1,020 \text{ MMBtu}) = 1.76E-03 \text{ lb hexane/MMBtu}$.

³⁷⁸ $(1.76E-03 \text{ lb hexane/MMBtu}) \times (2,250 \text{ MMBtu/hour}) \times (8,528 \text{ hours/year}) \times (1 \text{ ton}/2000 \text{ lb}) \times (2 \text{ turbines}) = 16.93 \text{ ton/yr}$.

³⁷⁹ Ola Maurstad, Massachusetts Institute of Technology, An Overview of Coal based Integrated Gasification Combined Cycle (IGCC) Technology, September 2005, MIT LFEE 2005-002 WP; http://sequestration.mit.edu/pdf/LFEE_2005-002_WP.pdf, attached as Ex. 139.

³⁸⁰ See, e.g., Krishnan G., SRI, and Gupta R., Research Triangle Institute, Development of Disposable Sorbents for Chloride Removal from High Temperature Coal-Derived Gases, Final Technical Report, September 1999, p. 1; http://www.fischer-tropsch.org/DOE/DOE_reports/30005/30005-02/30005-02-fnal.pdf, attached as Ex. 140.

³⁸¹ Ap., Table C-23.1, pp. C-84 to C-87.

³⁸² Permit Summary, p. 2.

³⁸³ Application, p. 12.-1.

and Louisiana Gasification Technologies, Inc. (“LGTI”) facilities.³⁸⁴ The Application provides no discussion whatsoever why these emission factors were not deemed equally applicable to combustion of SNG at the Taylorville facility and instead zero emissions were assumed for combustion of these gases.

Based on the higher of the two SNG emission factors from the Kentucky NewGas application (from LGTI stack tests), emissions of HCl from the CCCTs during normal operations (no startup/shutdown) at the Taylorville facility can be estimated at 6.9 ton/yr.³⁸⁵ When adding these HCl emissions to the Application’s estimate of 19.24 ton/yr of total facility-wide HAP emissions, the revised total facility-wide HAP emissions of 26.14 ton/yr exceed the major source threshold of 25 tons per year for total HAPs. Emissions of HCl during startup/shutdown and from other syngas and/or SNG-fired sources would further increase the facility-wide total. Thus, the facility is a major source of HAPs.

Actual emissions of HCl from the Taylorville facility may be considerably higher than the above estimated 6.9 ton/year because of the substantially higher chlorine content in the Illinois basin coal that would be gasified at the Taylorville facility compared to the western subbituminous coal from Rochelle mine in the Powder River Basin in Wyoming that was gasified at LGTI. The chlorine content of coal gasified at LGTI was measured at 0.0039 percent by weight (% wt).³⁸⁶ The Application, Permit Summary and Draft Permit are silent on the chlorine content of the coal the operator will gasify at the facility. However, a cost report developed for the Illinois Commerce Division shows that the Applicant considers use of coal from the Illinois Herrin and Springfield seams with a maximum design chlorine content of 0.35% wt.³⁸⁷ Review of the Illinois State Geological Survey (“ISGS”) database for coal quality shows that the chlorine content in Herrin and Springfield coal seams is often considerably higher with up to 0.97% wt and 0.74% wt, respectively.³⁸⁸ Thus, considering that the chlorine content in Illinois basin coal is almost two orders of magnitude higher than that of western subbituminous coal gasified at LGTI, one can reasonably expect that HCl emissions from Taylorville will be correspondingly higher and will exceed the major source thresholds of 10 and 25 ton/yr for both single and total HAPs.

³⁸⁴ Air Permit Application for New SNG Production Facility, Kentucky NewGas, Central City, KY, Volume 1 of 2, PSD/Title V Air Permit Application, Appx. C, Table C-22.3, p. C-78, and Table C-22.4, p. 79; <http://valleywatch.net/wp-content/uploads/docs/KY%20NewGas%20Volume%201%20Application.pdf>, attached as Ex. 141; Wabash River: syngas combustion emission factor = 4.8E-06 lb HCl/MMBtu, SNG combustion emission factor = 9.93E-07 lb HCl/MMBtu; LGTI: syngas combustion emission factor: 7.85E-04 lb HCl/MMBtu, SNG combustion emission factor = 3.59E-04 lb HCl/MMBtu.

³⁸⁵ $(3.59E-04 \text{ lb HCl/MMBtu})(2,250 \text{ MMBtu/hr/turbine})(2 \text{ turbines})(8,528 \text{ hr/year})(1 \text{ ton}/2000 \text{ lb}) = 6.89 \text{ ton Hg/year}$.

³⁸⁶ Electric Power Research Institute and U.S. Department of Energy, Summary Report: Trace Substance Emissions from a Coal-Fired Gasification Plant, DCN 96-643-004-009, October 1999, p. 2-1 and Table 3-1, p. 3-4 (Ex. 115).

³⁸⁷ Wood Mackenzie Study, p. 9.

³⁸⁸ Compare Illinois State Geological Survey, Illinois Coal Quality Data; <http://www.isgs.uiuc.edu/maps-data-pub/coal-maps/strat-database/coal-quality-nonconf.xls>.

The Draft Permit requires the Applicant to periodically test for the chlorine content of the coal (Cond. 4.1.7-2.c.ii.B and 4.1.9.a) and the raw syngas at the outlet of the gasifiers, sour syngas at the inlet to the AGR unit, sweet syngas at the outlet of the AGR Unit, and SNG at the outlet of the gasification block (Cond. 4.1.9.b.). However, exceedance of the major source threshold by HCl emissions would not be detected because the Permit fails to lay out a procedure HCl for developing emission factors for based on these test results for the various emission units or require application of these emission factors in determining facility-wide HAP emissions. For example, the Draft Permit does not require source testing for HCl in turbine exhaust turbines and does not require that instead the chlorine content of SNG measured at the outlet of the gasifiers be used to develop an emission factor for HCl emissions from the turbines. Further, the Draft Permit does not require that unit-specific and facility-wide emissions be estimated and compared to the major source threshold(s) for single and total HAPs. The Draft Permit should be revised to include an unambiguous calculation procedure.

e. Other HAP Emissions Were Omitted

Similar to hydrogen chloride, the Applicant failed to account for emissions of a number of other HAPs including benzo(e)pyrene, carbon disulfide, dichloromethane (methylene chloride), hydrogen cyanide, perylene, and phenanthrene from sources that combust SNG including the CCCTs, the AGR vent catalytic oxidizer, the SRU thermal oxidizer, auxiliary boiler, coal milling and drying stack, or the methanation startup heater. Again, the permit record provides no discussion why the emission factors developed for the Kentucky NewGas SNG production facility were not deemed equally applicable to combustion of SNG at the Taylorville facility and instead zero emissions were assumed for combustion of these gases.

f. Malfunction Emissions Were Not Accounted for in Potential to Emit

The periods when a facility starts up, shuts down, or malfunctions are among the most dangerous because facilities may release high levels of pollution. As a result, the Clean Air Act imposes strict emissions limitations on startup, shutdown, and malfunction periods. IEPA ignored such limits by not properly determining emissions during malfunction events, and thus failing to regulate the emissions through MACT emission standards.

Every industrial facility faces the possibility of an “upset” condition. At the Taylorville facility, this could, for example, include a malfunction of the gasifier technology. While it is impossible to know if and when problems will arise, emissions associated with malfunctions must nonetheless be included in the facility’s potential emit. As discussed in detail above, “potential to emit” is the “maximum capacity of a stationary source to emit a pollutant under its physical and operational design.” *See* IL ST CH 415 § 5/39.5; *see also* 40 C.F.R. §§ 63.2, 63.41. This is essential the worst case scenario of potential emissions, which includes emissions during unexpected malfunctions. Moreover, startup, shutdown and malfunction events are unquestionably regulated under the Clean Air Act. *See, e.g.*, 65 Fed. Reg. 70,792, 70,793 (Nov. 28, 2000) (EPA rulemaking “reiterate[ing] that, under the Act, all excess emissions during startups, shut down, or malfunction episodes are violations of applicable emission limitations.”)

Despite the legal requirements to calculate and regulate these emissions, the Draft Permit does not account for HAP emissions from malfunction events.

D. THE TAYLORVILLE FACILITY IS NOT A SYNTHETIC MINOR SOURCE OF HAPS AS THE DRAFT PERMIT FAILS TO INCLUDE ADEQUATE TERMS AND CONDITIONS TO CREATE FEDERALLY AND PRACTICALLY ENFORCEABLE LIMITATIONS ON TAYLORVILLE'S POTENTIAL TO EMIT HAPS BELOW MAJOR SOURCE EMISSION THRESHOLDS.

As detailed above, the Taylorville Energy Center is not a genuine minor source of HAPs as it will easily exceed the significance thresholds for a number of pollutants. As discussed above, a “synthetic minor” source of HAPs is one with potential emissions in excess of major source emission thresholds except that enforceable limitations (practically enforceable) on the source’s potential to emit are imposed to keep the source from emitting at or above major source emission thresholds. Therefore, IEPA could only find the Taylorville Energy Center is a minor source if the permit establishes practically enforceable limitations that prevent it from exceeding those significance thresholds. The draft Permit does not meet that standard, so IEPA cannot deem this facility a synthetic minor source.

In order for IEPA to find that this facility is a synthetic minor source, the agency would have to quantify the facility’s true potential to emit (worst case scenario) of methanol, nonmetallic HAPs, hexane, and hydrogen chloride and then issue a permit that includes enforceable limitations on those pollutants. The Draft Permit does not currently do that.

Draft Permit Condition 3.4.b establishes only facility-wide emission limits for lead and mercury at 0.22 and 0.10 ton/year, respectively. The Draft Permit requires analysis of the metals content a) in conjunction with emissions testing of the AGR unit and SRU; b) within 90 days of acceptance of a feedstock from a new source; c) within 90 days of a written request from IEPA; and d) at least once every two calendar years.³⁸⁹ The Draft Permit further requires that the Permittee keep a file containing the emission factors that the Permittee uses to calculate emissions of methanol, mercury, hydrogen chloride, hydrogen fluoride and other HAPs from the flare, the AGU, and the SRU with supporting documentation as well as records for total monthly and annual total HAP emissions from the flare, the AGU, and the SRU.³⁹⁰ However, nowhere does the Draft Permit set out the formula for the emission respective calculations, or require that the Applicant demonstrate that monthly or annual total HAP emissions do not exceed the permit limits. Thus, the emission limits for HAPs are not enforceable. Therefore, IEPA cannot find that this facility is a synthetic minor facility.

³⁸⁹ Draft Permit, Cond. 4.1.9, p. 33.

³⁹⁰ Draft Permit, Cond. 4.1-10-2.b.i and b.iv, p. 35, Cond. 4.1.10-3.a.i and a.iv, and Cond. 4.1.10-4.f.i and f.iv.

V. THE IEPA MUST REVISE THE PERMIT SO THAT THE EMISSION LIMITATIONS COMPLY WITH THE UTILITY MACT RULE

To the extent that IEPA may claim that the current Draft Permit includes MACT emission limits, such claims are belied by the permit conditions. The Permit does not comply with the new standards of the Utility MACT Rule.

A. BACKGROUND ON THE RECENT UTILITY MACT RULE.

On December 20, 2000, U.S. EPA made a determination that it was appropriate and necessary to regulate coal- and oil-fired electric generating units (“EGUs”) under CAA section 112 and added such units to the CAA section 112(c) list (112 list) of source categories that the agency must regulate. On January 30, 2004, U.S. EPA proposed section 112 standards for mercury emissions from coal-fired EGUs and nickel emissions from oil-fired EGUs, and, in the alternative, proposed to remove EGUs from the section 112 list based on a finding that it was neither appropriate nor necessary to regulate EGUs under this section of the Clean Air Act. At that time EPA also proposed to regulate mercury from coal-fired EGUs under CAA section 111. On March 29, 2005, U.S. EPA issued a final revision of the appropriate and necessary finding for coal- and oil-fired EGUs and removed such units from the section 112 list. EPA never finalized the proposed section 112 standards for Hg and Ni, but did finalize the regulation under section 111 to reduce mercury emissions from coal-fired EGUs.

On February 8, 2008, the D.C. Circuit vacated both the 2005 action to remove EGUs from the section 112 list and the section 111 rule to limit mercury emissions. The United States Court of Appeals for the District of Columbia determined that U.S. EPA violated the CAA by removing EGUs from the 112 list. As a result, EGUs remain a CAA section 112(c) listed source category.

In response to the D.C. Circuit Court’s vacatur, on March 16, 2011, U.S. EPA proposed section 112 air toxics standards for all coal- and oil-fired EGUs that reflect the application of the maximum achievable control technology (“MACT”) consistent with the requirements of the CAA. The proposal was published in the Federal Register on May 3, 2011. Thus IEPA was aware of the standards in the proposed rule.

On December 21, 2011, the U.S. EPA signed a rule to reduce emissions of toxic air pollutants from power plants (commonly referred to as the “Utility MACT Rule”).³⁹¹ Specifically, these mercury and air toxics standards for power plants will reduce emissions from new and existing coal and oil-fired electric utility steam generating units. The final Utility MACT Rule identifies two subcategories of coal-fired EGUs, four subcategories of oil fired EGUs, and a subcategory for units that combust gasified coal or solid oil (integrated gasification combined cycle (“IGCC”) units) based on the design, utilization, and/or location of the various

³⁹¹ See National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units (“Final Utility MACT Rule”), available at <http://www.epa.gov/airquality/powerplanttoxics/pdfs/20111216MATSFfinal.pdf>, attached as Exhibit 118.

types of boilers at different power plants. The rule includes emission standards and/or other requirements for each subcategory. This new rule applies to the Taylorville facility since construction has not begun yet and the Utility MACT Rule applies to facilities that commenced construction after May 3, 2011. *See* Final Utility MACT Rule at 872, 876, 982, 985; *see also* 40 CFR. §§ 63.9981, 63.9982, 63.9985, 63.10042.

B. THE TAYLORVILLE FACILITY BURNS SYNTHETIC GAS DERIVED FROM COAL AND NOT NATURAL GAS

Tenaska is attempting to avoid the EGU MACT regulations by defining the gas produced here as “synthetic natural gas” or SNG, to distinguish it from synthetic gas, which is made by IGCC plants and is covered by EGU MACT. However, such an interpretation is directly at odds with the plain language of the Utility MACT Rule.

The final rule defines “[i]ntegrated gasification combined cycle electric utility steam generating unit or IGCC” as “an electric utility steam generating unit meeting the definition of ‘fossil fuel-fired’ that burns a synthetic gas derived from coal and/or solid oil derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No coal or solid oil-derived fuel is directly burned in the unit during operation.” *See* Final Utility MACT Rule at 985; *see also* 40 C.F.R. § 63.10042.

As mentioned previously, the Utility MACT Rule only applies to coal and oil-fired electric utility steam generating units (EGUs). “This final rule does not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but that combusts natural gas exclusively or natural gas in combination with another fossil fuel where the natural gas constitutes 90.0 percent or more of the average annual heat input during any 3 consecutive calendar years or 85.0 percent or more of the annual heat input in one calendar year. We consider such units to be natural gas-fired EGUs notwithstanding the combustion of some coal or oil (or derivative thereof) and such units are not subject to this final rule.” *See* Final Utility MACT Rule at 26, *see also*, 40 C.F.R. § 63.9983.

The rule goes on to define “natural gas” as “a fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.” *See* Final Utility MACT Rule at 985 (emphasis added); *see also*, 40 C.F.R. § 63.9983.

Therefore, the rule unquestionably regulates IGCC plants that burn a synthetic gas derived from coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one

calendar year in a combined-cycle gas turbine. Moreover, a facility cannot claim that it is exempted from the standards of this rule if the gas it burns is a “coal-derived gas.” Therefore, Tenaska cannot attempt to avoid the applicability of this rule by claiming it is burning a synthetic natural gas or SNG.

C. THE TAYLORVILLE FACILITY DOES NOT COMPLY WITH THE MACT STANDARDS ARTICULATED IN THE UTILITY MACT RULE.

For all existing and new coal-fired EGUs, the final Utility MACT Rule establishes numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals), and HCl (a surrogate for all toxic acid gases). The rule also establishes alternative numeric emission standards, including SO₂ (as an alternate to HCl), individual non-mercury metal air toxics (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM) for certain subcategories of power plants. The Final Utility MACT Rule establishes the following specific emission limits for new IGCC plants:

If your EGU is in this subcategory ...	For the following Pollutants ...	You must meet the following emission limits and work practice standards ...	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5...
3. IGCC unit.	a. Filterable particulate matter (PM)	7.0E-2 lb/MWh ^a 9.0E-2 lb/MWh ^b	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals: Antimony (Sb) Arsenic (As) Beryllium (Be) Cadmium (Cd) Chromium (Cr) Cobalt (Co) Lead (Pb) Manganese (Mn) Nickel (Ni) Selenium (Se)	2.0E-2 lb/GWh 2.0E-2 lb/GWh 1.0E-3 lb/GWh 2.0E-3 lb/GWh 4.0E-2 lb/GWh 4.0E-3 lb/GWh 9.0E-3 lb/GWh 2.0E-2 lb/GWh 7.0E-2 lb/GWh 3.0E-1 lb/GWh	Collect a minimum of 2 dscm per run.
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348-032 or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO ₂) ^c	4.0E-1 lb/MWh	SO ₂ CEMS.
	c. Mercury (Hg)	3.0E-3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.

a Duct burners on syngas; gross electric output.

b Duct burners on natural gas; gross electric output.

c You may not use the alternate SO₂ limit if your EGU does not have some form of FGD system and SO₂ CEMS installed.

See Final Utility MACT Rule at 995-96; *see also*, 40 C.F.R., Subpart UUUUU, Table 1.

As this chart demonstrates, the final Utility MACT Rule establishes numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals), and HCl (a surrogate for all toxic acid gases). The rule also establishes alternative numeric emission standards, including SO₂

(as an alternate to HCl), individual non-mercury metal air toxics³⁹² (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM). *See* Final Utility MACT Rule at 995-996; *see also*, 40 C.F.R., Subpart UUUUU, Table 1.

The Draft Permit only establishes two emission limits for facility-wide emissions for lead (0.22 ton/yr) and mercury (0.10 ton/yr).³⁹³ Draft Permit sets an annual emission limit for mercury at 0.1 ton/yr,³⁹⁴ which translates to an emission rate of 0.03 pounds per Gigawatt-hour (“lb/GWh”) of mercury.³⁹⁵ This emission rate exceeds the mercury limit set by the new Utility MACT rule for IGCCs of 3.0E-03 lb/GWh by a factor of ten. Thus, the annual emission limit for mercury set by the Draft Permit (0.01 ton/yr) fails to comply with the requirements of the new Utility MACT rule.

Table 17 compares facility-wide emissions for Taylorville calculated based on the Utility MACT limits for emission factors and facility-wide emissions as calculated by the Applicant.

³⁹² Antimony (“Sb”), Arsenic (“As”), beryllium (“Be”), cadmium (“Cd”), chromium (“Cr”), cobalt (“Co”), lead (Pb), manganese (“Mn”), nickel (“Ni”), and selenium (“Se”).

³⁹³ Draft Permit, Cond. 3.4.b.

³⁹⁴ Draft Permit, Cond. 3.4.b.

³⁹⁵ $(0.1 \text{ ton Hg/year})(2,000 \text{ lb/ton})(1 \text{ year}/8,760 \text{ hours})(1/770 \text{ MW})(1,000 \text{ MW/GW}) = 0.0297 \text{ lb Hg/GWh}$.

**Table 17
Taylorville Facility-wide Emissions Compared to Utility MACT Emission Limits**

	Utility MACT Emission Factor Limit	Permissible Facility-wide Emissions based on Utility MACT^a (ton/yr)	Application^b (ton/yr)	Exceeds MACT Limit?
a. Filterable PM OR Total non-Hg HAP metals OR Antimony (Sb) Arsenic (As) Beryllium (Be) Cadmium (Cd) Chromium (Cr) Cobalt (Co) Lead (Pb) Manganese (Mn) Nickel (Ni) Selenium (Se)	9.00E-02 lb/MWh 4.00E-01 lb/GWh 2.00E-02 lb/GWh 2.00E-02 lb/GWh 1.00E-03 lb/GWh 2.00E-03 lb/GWh 4.00E-02 lb/GWh 4.00E-03 lb/GWh 9.00E-03 lb/GWh 2.00E-02 lb/GWh 7.00E-02 lb/GWh 3.00E-01 lb/GWh	3.04E+02 1.35E+00 6.75E-02 6.75E-02 3.37E-03 6.75E-03 1.35E-01 1.35E-02 3.04E-02 6.75E-02 2.36E-01 1.01E+00	2.39E+02 4.20E-01 8.72E-03 1.60E-02 7.72E-03 2.27E-02 2.90E-02 2.91E-03 2.20E-01 4.63E-02 1.00E-01 1.24E-02	no no no no YES YES no no YES no no no
b. Hydrogen chloride (HCl) OR Sulfur dioxide (SO ₂)	2.00E-03 lb/MWh 4.00E-01 lb/MWh	6.75E+00 1.35E+03	6.20E-01 6.97E+02	no no
c. Mercury (Hg)	3.00E-03 lb/GWh	1.01E-02	1.03E-01	YES

a (Utility MACT Emission Factor Limit in lb/MWh)(8,760 hours/year)(770 MW)(1 ton/2000 lb)
(Utility MACT Emission Factor Limit in lb/GWh)(8,760 hours/year)(770 MW)(GW/1000 MW) (1 ton/2000 lb)

b Ap., Appx. C, Table C-23.1.

Table 17 shows that, in addition to exceeding the emission limit for mercury, facility-wide emissions from Taylorville would exceed the alternate Utility MACT thresholds for beryllium, cadmium, and lead. As discussed elsewhere, the Applicant substantially underestimated facility-wide PM emissions. As a result, facility-wide emissions of SO₂ and PM likely also exceed the Utility MACT emission limits. The Permit must be revised to reflect the emission limits and compliance testing requirements of the Utility MACT Rule (in lb/GWh or lb/MWh) and provide adequate demonstration that these limits and requirements can be met.

With regard to the noncompliance with the mercury emission limits of the Utility MACT rule, the Applicant, apparently seeking to remedy this situation, requested a lower permit limit in a letter to IEPA dated November 8, 2011:

“We wish to lower the annual facility-wide mercury emission limit, as stated in Condition 3.4(b) of the draft permit, from 0.10 tons (200 pounds) per year to 0.01 tons (20 pounds) per year. This revised limit, which represents a 90% reduction, is based on the mercury limit for new coal-fired and IGCC units expected to be included in the forthcoming final National Emissions Standards for

Hazardous air pollutants from Coal-and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63 Subpart UUUUU) rule.”³⁹⁶

In its letter, the Applicant offers to furnish revised emission calculations upon request but provides no explanation whatsoever how this 90% reduction is achievable; instead, the Applicant simply requests the lower permit limit to comply with the new Utility MACT Rule. This is not acceptable. The Applicant must provide sufficient evidence for its emission estimates which, as explained infra, are the basis for its compliance calculations for HAPs including mercury.

VI. THE AIR QUALITY IMPACTS ANALYSES ARE FLAWED AND INADEQUATE

Consultants for the proposed TEC prepared air dispersion modeling in support of Tenaska’s permit application to the IEPA. TEC’s modeling is presented in an October 2010 report that outlines their modeling methodology and results.³⁹⁷ IEPA reviewed, audited, and re-modeled TEC’s air quality modeling; however, they eventually relied solely on the Applicant’s modeling analysis to support their permit review decisions.³⁹⁸ Both Tenaska and IEPA used the U.S. EPA preferred air quality model, AERMOD, which is an acronym for the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee’s Dispersion Model.

Air dispersion modeling is used to demonstrate compliance with the NAAQS and PSD increments in ambient air. Modeled concentrations are added to a regional background value to determine the total concentration used in comparison to the NAAQS or increments. It is important that the emissions used in this modeling are accurate. As discussed in extensive detail above, emissions of PM10, PM 2.5, and SO₂ were underestimated by using unrealistically high control efficiencies and ignoring certain sources of those emissions.

In addition, the Applicant’s modeling includes a number of assumptions and methodologies that will under-estimate modeled air quality impacts. The under-estimates render both the permit application and IEPA’s review flawed and inadequate for verifying compliance with the NAAQS and PSD increments. Specifically, TEC’s modeling includes the following inappropriate methodologies:

- TEC uses non-preferred meteorological data that include an unrealistically high number of calm hours. Since calm hours cannot be used by the air dispersion model, the modeling is not properly assessing compliance with the NAAQS and PSD increments.

³⁹⁶ Letter from Larry G. Carlson, Christian County Generation, LLC, to Dean Studer, Illinois EPA, Re: Public Comments – Taylorville Energy Center Draft Air Permit, Christian County Generation, LLC, Application No. 05040027, November 8, 2011; received from IEPA in response to FOIA request, attached as Ex. 109a.

³⁹⁷ Updated Prevention of Significant Deterioration and State Construction Permit Application for the Taylorville Energy Center, Christian County Generation, Taylorville, Illinois, Permit No. 05040027, Volume 2 of 3, Class II Area Air Quality Modeling Report, October 2010 (“Modeling Report”).

³⁹⁸ IEPA, Project Summary for a Construction Permit Application from Christian County Generation, LLC for the Taylorville Energy Center Christian County, Illinois, October 17, 2011 (“Project Summary”).

- TEC’s modeling is based on underestimated fugitive PM₁₀ and PM_{2.5} emissions from transfer points and storage piles. When these PM₁₀ and PM_{2.5} emissions are corrected, the modeling predicts violations of the 24-hour PM₁₀ NAAQS, the 24-hour PM₁₀ PSD increment, and the 24-hour PM_{2.5} NAAQS.
- TEC’s modeling uses under-estimated flare SO₂ emissions that will occur during planned startup and shutdown. Once corrected, the modeling shows violations of the one-hour SO₂NAAQS.
- TEC uses an unacceptable and inappropriate set of screening tables, rather than actual air dispersion modeling, to estimate ozone impacts from the proposed project. In addition, the VOC emissions from the proposed project are greatly under-estimated in the permit application, thus making TEC’s ozone analysis even more inadequate.

We identified the AERMOD model runs that TEC used as the basis for both their permit application and IEPA’s project summary. These files were included in a hard drive of files provided to Sierra Club and Natural Resources Defense Council on December 14, 2011. In our modeling analysis we used TEC’s model inputs as a starting point, and then we modified the specific inputs to reflect the corrected PM₁₀, PM_{2.5} and SO₂ emissions as discussed elsewhere in our comments. We also removed all the non-TEC emission sources from the model inputs. This means that all of our modeled results are due only to the proposed TEC facility. If we had included the other PSD and NAAQS-consuming sources in our analysis, the model results would be even higher than we report below.

We used AERMOD versions 11103 and 11353 for our modeling analysis. AERMOD v. 11353 was released by USEPA on 12/21/2011, and reflects the most recent version available. In our analyses of the air impacts from TEC’s emissions, we found no differences in the results between these two models.

This section discusses how revised modeling, using corrected emission rates and corrected modeling assumptions, shows how the TEC will exceed the 24-hour PM₁₀ NAAQS and PSD increment, the 24-hour PM_{2.5} NAAQS, and the 1-hour SO₂ NAAQS. Moreover, these comments will address why IEPA cannot rely on the analysis provided by Tenaska to verify compliance with the ozone NAAQS as it is fundamentally flawed.

A. LEGAL BACKGROUND ON NAAQS AND INCREMENTS

The Clean Air Act’s PSD program regulates air pollution in areas of the country deemed to be in “attainment” or “unclassifiable” with respect to the NAAQS. *See* 42 U.S.C. §§ 7471, 7475. NAAQS are “maximum concentration ‘ceilings’ measured in terms of the total concentration of a pollutant in the atmosphere.” NSR Manual at C.3. Congress charged EPA with developing NAAQS for air pollutants whose presence in the atmosphere in excess of certain

concentration levels could “reasonably be anticipated to endanger public health or welfare.”³⁹⁹ 42 U.S.C. § 7408(a)(1)(A); *see* 42 U.S.C. § 7409.

In geographical areas deemed to be in “attainment” for any of these pollutants, the ambient air quality meets the NAAQS for that pollutant. 42 U.S.C. § 7407(d)(1)(A)(ii). In areas designated as “unclassifiable,” air quality cannot be classified on the basis of available information as meeting or not meeting the NAAQS. 42 U.S.C. § 7407(d)(1)(A)(iii).⁴⁰⁰ Parties who wish to construct “major emitting facilities”⁴⁰¹ in attainment or unclassifiable areas must obtain preconstruction approval in the form of PSD permits to build such facilities. 42 U.S.C. § 7475. Christian County, the proposed site of the Taylorville Energy Center, lies in an “attainment area” for all regulated pollutants.

As part of the permit issuance process, the PSD regulations at 40 C.F.R. § 52.21 require, among other things, that new major stationary sources of air pollution, and any major modification of such sources, be carefully reviewed prior to construction to ensure that emissions from such facilities will not cause an exceedance of the NAAQS or applicable PSD ambient air quality “increments.”⁴⁰² These permits must also require compliance with emissions limits constituting BACT to minimize emissions of regulated pollutants. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(b)(23), (j)(2)-(3).

To demonstrate that a project will not cause or contribute to a violation of NAAQS or PSD Increment, air dispersion modeling is required. Air dispersion modeling uses complicated mathematical models to predict the impact an air pollution source will have on air quality in a geographical area. This modeling must be conducted based on the maximum allowable operating conditions and emission rates during the applicable time period. NSR Manual at C.45-46. For example, demonstrations that the source will not violate the 24-hour PM₁₀ PSD Increment must be based on the maximum emissions during any 24-hour period, subject to enforceable limits during the time period. Similarly, demonstrates that the source will not violate the 1-hour SO₂ NAAQS must be based on the maximum emissions during any 1-hour period, subject to enforceable limits during that time period.

B. ACTUAL ELECTRONIC EMISSION CALCULATION SPREADSHEETS WERE NEVER PROVIDED TO IEPA SO THE PUBLIC DID NOT HAVE ADEQUATE INFORMATION TO FULLY ANALYZE THE AIR QUALITY ANALYSIS

³⁹⁹ NAAQS have been established for six criteria pollutants: sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone, and lead. *See* 40 C.F.R. §§ 50.4 - 50.13.

⁴⁰⁰ Areas may also be designated as “nonattainment,” meaning that the concentration of a pollutant in the ambient air does not meet the NAAQS for that pollutant. 42 U.S.C. § 7407(d)(1)(A)(I). The PSD program is not applicable, however, in non-attainment areas. *See* 42 U.S.C. § 7471.

⁴⁰¹ A “major emitting facility” is a stationary source in any of certain listed stationary source categories that emits or has the “potential to emit” 100 tons per year (“tpy”) or more of any air pollutant, or any other source that has the potential to emit 250 tpy or more of any air pollutant. *See* 42 U.S.C. § 7479(1).

⁴⁰² A PSD “increment” refers to “the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant.” NSR Manual at C.3; *see also* 40 C.F.R. § 52.21(c) (setting forth increments for regulated pollutants).

The documents provided to Sierra Club and Natural Resources Defense Council by IEPA included emission calculations in Adobe Acrobat.PDF file format. In this encrypted form, it is impossible to verify the numerous calculations needed for the complete Taylorville Energy Center emission inventory. The Sierra Club and Natural Resources Defense Council have reviewed many power plant applications, and the usual mode for responding to the emission calculation data request is to provide unlocked Excel spreadsheets showing the equations and assumptions as they were actually applied.

IEPA does not have any electronic form of the emission calculations, except the.PDF files sent to Sierra Club. This is disconcerting for three reasons:

1. The actual emission calculations applied in the permit application are never made available to the reviewing public. One would hope that the equations shown on the .PDF listings are the same as those actually used in the final calculations, but there is no way to know for sure unless the equations are checked by hand (many thousands of times), or by viewing the calculations in the program used to perform the inventory (i.e., Excel spreadsheets).
2. By not having the native spreadsheets, IEPA could not itself have reviewed the facility emission calculations in a complete fashion. At best, they could only spot-check. This is highly problematic given that the emission calculations for certain pollutants, such as particulate matter, were projected to decrease by a magnitude of 10 since the last PSD application for this permit. Without these native spreadsheets it is impossible for the agency to determine if there are emission calculation errors and thus verify that this facility will not lead a violation of the NAAQS or increment consumption (without any necessary corrections to the modeling methods discussed below).
3. Emission calculation spreadsheets were obviously created by Tenaska, and could have been easily provided to IEPA and any reviewers requesting the files. Tenaska, however, has never made these Excel files available. Instead, they encrypt the data in Adobe .PDF form, where it is impossible to scrutinize what equations were actually used for the permit application.

Tenaska's actions are at odds with EPA's policy that meaningful public review requires full transparency by the applicant of its modeling work. The EPA does not accept analyses prepared unless a transparent view of the actual applied dispersion modeling equations is provided. The U.S. EPA Guideline on Air Quality Models states clearly: "The developer must be willing to make the model available to users at reasonable cost or make it available for public access through the Internet or National Technical Information Service: the model cannot be proprietary."⁴⁰³ Moreover, "air quality models used in U.S. regulatory programs must be in the public domain at reasonable cost. This is because the source code needs to be open for public

⁴⁰³ United States Environmental Protection Agency, 2003, Guideline on Air Quality Models. 40 CFR 51, Appendix W, Section 3.1.1(c)(vi) attached as Ex. 143, appw_05.pdf.

access and scrutiny to enable meaningful opportunity for public comment on new source permits, PSD increment consumption and SIPs.”⁴⁰⁴ *In re Hawaii Elec. Light Co., Inc.*, 8 E.A.D. 66, 102 (EAB 1998) (quoting CAA § 165(e)(3)(c), 42 U.S.C. § 7475(e)(3)(c)) (“Congress has determined that the air quality analysis required by the regulations ‘shall be available at the time of the public hearing on the application for such permit.’”).

Similarly, without the actual electronic spreadsheets used to perform the TEC emission calculations, meaningful opportunity for public comment on new source permits, including compliance with NAAQS and PSD increment consumption is not possible. IEPA should require Tenaska to submit this information and re-do its permit analysis. *See, e.g., In re Hawaii Elec. Light Co., Inc.*, 8 E.A.D. 66, 102-103 (EAB 1998) (remanding permit where data relevant to the impact analysis was not subject to the public scrutiny contemplated by the statute and applicable regulations).

C. THE MODELING RESULTS ARE BASED ON UNDERESTIMATED EMISSIONS OF PM₁₀, PM_{2.5}, AND SO₂

The Applicant submitted air quality modeling as required to ensure protection of NAAQS, but inappropriately modeled underestimated PM and SO₂ emissions instead of maximum or worst-case emissions. As discussed in Section II above, Tenaska underestimated emissions of PM₁₀ and PM_{2.5} by excluding certain fugitive emission sources from its calculations, assuming unrealistic control efficiencies for numerous sources, and other noted problems, and underestimated SO₂ emissions by not accounting for the maximum emissions from the flares during planned startup/shutdown and failing to account for any emissions from the flares during malfunction events. Despite the fact that there are no hourly or daily emission limits on these emission points, and the fact that the pollution abatement techniques are in actuality far less effective than the applicant assumed, IEPA assumed emission rates for purposes of modeling that do not reflect the worst-case emissions during the 24-hour averaging period for compliance with the PM NAAQS and PSD Increment and 1-hour averaging period for compliance with the SO₂ NAAQS. As such, the modeling carried out by Tenaska and IEPA does not demonstrate the requisite compliance with the applicable NAAQS and PSD Increments. In addition, upon correction of some or all of the erroneous assumptions, detailed in length above, to represent worst case conditions as required for air impact modeling, air quality modeling shows that the project does not satisfy the CAA’s requirements to not violate a NAAQS or exceed an increment consumption limit. Therefore, IEPA cannot issue a PSD permit for the TEC.

D. THE 2003 – 2007 SPRINGFIELD AIRPORT DATA USED BY THE APPLICANT ARE NOT THE PREFERRED DATA FOR REGULATORY MODELING APPLICATIONS

Tenaska used Springfield, Illinois Capital Airport surface data and Lincoln-Logan upper air data from 2003 through 2007 in their permit application modeling. These years are not the preferred data for modeling air impacts from the proposed TEC facility.

⁴⁰⁴ Id.

U.S. EPA's definition of preferred meteorological data includes the most recent five years of National Weather Service (NWS) data. Currently, this condition is satisfied using 2006 through 2010 Automated Surface Observing Station (ASOS) data collected at the most site-appropriate airport.

The definition of preferred data is found in EPA's Guideline on Air Quality Models. From Section 8.3.1.2 of the Guideline on Air Quality Models:

Five years of representative meteorological data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data should be *adequately representative*, and may be site specific or from a nearby NWS station.⁴⁰⁵

The Applicant prepared their air dispersion modeling in support of their permit application in the fall of 2010. At that date, meteorological data for years 2005 through 2009 were readily available and should have been used. When IEPA was reviewing and auditing TEC's modeling runs, meteorological data for years 2006 through 2010 were readily available.

More importantly, the meteorological data used in TEC's air quality modeling is based on airport wind measurements that include an over-stated number of calm conditions. This is a widely-known problem with airport data. In April 2011, U.S. EPA released a revised version of AERMET, the program that creates the meteorological data sets used by AERMOD. This revised version of AERMET can process one-minute ASOS data, thus eliminating the reporting artifact that causes an unrealistically high number of calm hours in the data sets. From U.S. EPA:

Surface meteorological data collected by the National Weather Service (NWS) and Federal Aviation Administration (FAA) are often used as the source of input meteorological data for AERMOD (EPA, 2010a). A potential concern related to the use of NWS meteorological data for dispersion modeling is the often high incidence of calms and variable wind conditions reported for the Automated Surface Observing Stations (ASOS) in use at most NWS stations since the mid-1990's. In the METAR coding used to report surface observations beginning July 1996, a calm wind is defined as a wind speed less than 3 knots and is assigned a value of 0 knots. The METAR code also introduced the variable wind observation that may include wind speeds up to 6 knots, but the wind direction is reported as missing, if the wind direction varies more than 60 degrees during the 2-minute averaging period for the observation. The AERMOD model currently cannot simulate dispersion under calm or missing wind conditions. To reduce the number of calms and missing winds in the surface data, archived 1-minute winds for the ASOS stations can be used to calculate hourly average wind speed and directions,

⁴⁰⁵ USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005 attached as Ex. 143, appw_05.pdf.

which are used to supplement the standard archive of hourly observed winds processed in AERMET (EPA, 2010b).⁴⁰⁶

Furthermore, in their modeling guidance for SO₂ NAAQS designations, U.S. EPA addresses the concern of calm hours in verifying compliance with the one-hour SO₂ NAAQS:

In AERMOD, concentrations are not calculated for variable wind (i.e., missing wind direction) and calm conditions, resulting in zero concentrations for those hours. Since the SO₂ NAAQS is a one hour standard, these light wind conditions may be the controlling meteorological circumstances in some cases because of the limited dilution that occurs under low wind speeds which can lead to higher concentrations. The exclusion of a greater number of instances of near-calm conditions from the modeled concentration distribution may therefore lead to underestimation of daily maximum 1-hour concentrations for calculation of the design value.⁴⁰⁷

Although U.S. EPA is referring to the one-hour SO₂ NAAQS in this particular instance, the concern regarding over-stated calm hours in the modeling data sets is also a problem when modeling other pollutants such as PM₁₀ and PM_{2.5}. This will be verified in our modeling comments on PM₁₀ and PM_{2.5} emissions presented below, which show significantly higher modeled impacts with our 2006 through 2010 meteorological data than from the Applicant's 2003 through 2007 data.

The 2003 through 2007 data sets modeled by the Applicant include 4,253 calm hours, or about 10 percent of the entire database. IEPA should have re-analyzed TEC's modeling using 2006 through 2010 meteorological data with one-minute ASOS data, and then used those years as the basis for their permit review decisions. The permit application modeling analysis is flawed from the beginning since both the Applicant and IEPA rely on non-preferred meteorological data with an unrealistically high number of calm hours.

In our review of the permit application modeling (and also to address U.S. EPA's concerns regarding calm winds), we developed 2006 through 2010 meteorological data that incorporate methods to reduce calm and missing hours (e.g. use one minute data and U.S. EPA's AERMINUTE program). The meteorological data required by AERMOD is prepared by AERMET. Required data inputs to AERMET are: surface meteorological data, twice-daily soundings of upper air data, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. AERMET creates the model-ready surface and profile data files required by AERMOD.

The 2006 through 2010 data sets we developed include 485 calm hours, or roughly one percent of the entire database. Most of these calm hours (375 out of 485) occurred during 2006. For years 2007 through 2010 there are only 110 total calm hours in our revised data set. As will

⁴⁰⁶ U.S. EPA, AERMINUTE User's Instructions, attached as Ex. 144, aerminute_userguide_11325.pdf.

⁴⁰⁷ U.S. EPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19, attached as Ex. 143 SO₂ Designations Guidance 2011-ocr.pdf.

be shown below, this preferred meteorological data set results in higher modeled impacts than the 2003 through 2007 data sets used by the Applicant in their permit application. A brief description of how we prepared the 2006 through 2010 data sets is as follows:

- Using AERMET v. 11059, we created an AERMOD-ready meteorological data set to model the proposed TEC facility. This data set covered five years, 2006 through 2010, and includes surface data from Springfield Capital Airport (KSPI) and upper air data from Lincoln-Logan County Airport (KILX).
- We used 2006 through 2010 Integrated Surface Hourly (ISH) data obtained from the National Climatic Data Center (NCDC). These data are readily available from yearly DVDs sold by NCDC or can be downloaded from their website. From the ISH dataset, we extracted ASOS data from the Springfield Capital Airport. This is the same location for surface data that were used by the Applicant and IEPA; however, we used the most recent preferred data with one-minute ASOS winds as described below.
- We obtained 2006 through 2010 one-minute ASOS wind data from the Springfield Capital Airport, which we processed with AERMINUTE versions 11059 and 11325. AERMINUTE v. 11325 was released by USEPA on 12/21/2011, and reflects the most recent version available. In our comparison analyses of the AERMOD-ready meteorological data sets created using one-minute ASOS wind data, we found no differences in the results between these two versions. We downloaded the one-minute data from the NCDC.⁴⁰⁸ We also input the ice-free wind instrument start and used default settings with AERMINUTE (9/25/2006). As a quality assurance measure, we compared values developed from the one-minute data with the corresponding ISH data file.
- We processed the ISH and one-minute ASOS surface data through AERMET Stage 1, which performs data extraction and quality control checks. We merged the AERMINUTE output files with the processed AERMET Stage 1 ISH and upper air data in AERMET stage 2.
- We used 2006 through 2010 upper air data from twice-daily radiosonde measurements obtained from Lincoln-Logan, IL. These data are in Forecast Systems Laboratory (FSL) format which we downloaded in ASCII text format from NOAA's FSL website.⁴⁰⁹ We downloaded and processed all reporting levels with AERMET.

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawinsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. We processed the FSL upper air data through AERMET Stage 1, which performs data extraction and quality control checks.

⁴⁰⁸ See: <ftp://ftp.ncdc.noaa.gov/pub/data/asos-onemin/>

⁴⁰⁹ Available at: <http://esrl.noaa.gov/raobs/>

- We used USEPA’s AERSURFACE program for extracting surface roughness, albedo, and daytime Bowen ratio for an area surrounding the ASOS site at Springfield Capital Airport. AERSURFACE uses land use and land cover (LULC) data in the U.S. Geological Survey’s 1992 National Land Cover Dataset to extract the necessary micrometeorological data. We used these 1992 LULC data for processing meteorological data sets which then serve as input to AERMOD.
- We used AERSURFACE v. 08009 to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site (Springfield Capital Airport). Using AERSURFACE, we extracted surface roughness in a one kilometer radius surrounding the data collection site. We also extracted Bowen ratio and albedo for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. We processed these micrometeorological data for seasonal periods using 30-degree sectors.
- We developed variable Bowen ratios, based on precipitation for each season and each year (2006 through 2010). We determined the seasonal moisture conditions (wet, average, dry) using 1981 through 2010 climatic mean monthly rainfall data for the Springfield Capital Airport.⁴¹⁰ For each season of each year, we compared the seasonal total rainfall to climatic means for that season. Seasonal rainfall less than 75% of climatic means was assessed as dry. We assessed seasonal rainfall greater than 125% of climatic means as wet.⁴¹¹ A Table of the precipitation conditions for determining seasonal Bowen ratios from Springfield Capital is included in Exhibit 151 (see modeling-attach-1.pdf).
- We did not fill missing hours in the meteorological data sets as the data files easily exceed USEPA’s 90% data completeness requirement.⁴¹² Annual wind roses of the AERMOD-ready meteorological data sets we created, individually by year for 2006 through 2010 for Springfield/Lincoln-Logan, are also included in Exhibit 151 (see modeling-attach-1.pdf).

E. REVISED MODELING RESULTS, USING CORRECTED PM₁₀ EMISSION RATES, EXCEED THE 24-HOUR PM₁₀ NAAQS AND PSD INCREMENT

We obtained the Applicant’s PM₁₀ emissions as modeled in support of their permit application, and made the following corrections to emission rates:

⁴¹⁰ See <http://www.ncdc.noaa.gov/oa/climate/normal/usnormals.html>

⁴¹¹ USEPA, Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT Appropriate and Necessary Analysis, March 16, 2011, p. 11, attached as Ex. 124, non-hg_risk_tsd.pdf.

⁴¹² USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 – 5-5, attached as Ex. 145, mmgrma.pdf.

Source Term (modeled as volume source)	Corrected PM ₁₀ Emissions (g/s)
Active Storage Dome or Inactive Pile Conveyor Loadout (modeled as TP1)	0.1534
Stackout Conveyor #3 to Inactive Pile Lowering Well (modeled as TP2)	0.1534
Inactive Pile Chain Reclaimer to Conveyor #4B (modeled as TP3)	0.0544
Inactive Coal Pile (modeled as PIL1)	1.2725

The basis for these corrected emissions is discussed infra.

We remodeled the Applicant's PM₁₀ emissions, with the above revisions, using USEPA's AERMOD air dispersion model. In addition, we removed all of the non-TEC PM₁₀ emission sources from our modeling analyses. Thus our PM₁₀ modeling results are due solely to the proposed TEC project emissions.

We modeled two meteorological data sets: The Applicant's 2003 through 2007 data and our 2006 through 2010 data using one-minute ASOS winds. For our PM₁₀ modeling analysis we used the same background 24-hour PM₁₀ concentration used by the Applicant (49 µg/m³).⁴¹³

Using the Applicant's 2003 through 2007 meteorological data, TEC's corrected PM₁₀ emissions result in a 183.4 µg/m³ highest second-high 24-hour air concentration. When added to the background concentration (49 µg/m³), the total one-hour PM₁₀ concentration is 232.4 µg/m³. This is a violation of the 24-hour PM₁₀ NAAQS, with or without adding the background concentration. These results are summarized in the following table.

Year of Meteorological Data	Highest 2 nd High 24-hr PM ₁₀ Concentration (µg/m ³)	Background 24-Hr PM ₁₀ Concentration (µg/m ³)	Total 24-Hr PM ₁₀ Concentration (µg/m ³)	24-Hr PM ₁₀ NAAQS (µg/m ³)	Easting Coordinate (meters)	Northing Coordinate (meters)
2003	120.8	49	169.8	150	306531.9	4385423.4
2004	138.2	49	187.2	150	306531.9	4385423.4
2005	140.7	49	189.7	150	306531.9	4385423.4
2006	183.4	49	232.4	150	306432.0	4385428.0
2007	137.8	49	186.8	150	306332.1	4385432.6

Based on the Applicant's 2003 through 2007 meteorological data, TEC's highest second-high 24-hour PM₁₀ concentration (183.4 µg/m³) also violates the 24-hour PM₁₀ PSD increment (30 µg/m³). Other modeled years show similar results, as summarized in the following table.

⁴¹³ Modeling Report, p. 5-6.

Year of Meteorological Data	Highest 2nd High 24-hr PM₁₀ Concentration (µg/m³)	24-Hr PM₁₀ PSD Increment (µg/m³)	Easting Coordinate (meters)	Northing Coordinate (meters)
2003	120.8	30	306531.9	4385423.4
2004	138.2	30	306531.9	4385423.4
2005	140.7	30	306531.9	4385423.4
2006	183.4	30	306432.0	4385428.0
2007	137.8	30	306332.1	4385432.6

Using our 2006 through 2010 meteorological data developed from one-minute ASOS winds, TEC's corrected PM₁₀ emissions result in a 208.2 µg/m³ highest second-high 24-hour air concentration. When added to the background concentration (49 µg/m³), the total one-hour PM₁₀ concentration is 257.2 µg/m³. This is a violation of the 24-hour PM₁₀ NAAQS, with or without adding the background concentration. These results are summarized in the following table.

Year of Meteorological Data	Highest 2nd High 24-hr PM₁₀ Concentration (µg/m³)	Background 24-Hr PM₁₀ Concentration (µg/m³)	Total 24-Hr PM₁₀ Concentration (µg/m³)	24-Hr PM₁₀ NAAQS (µg/m³)	Easting Coordinate (meters)	Northing Coordinate (meters)
2006	164.9	49	213.9	150	306432.0	4385428.0
2007	184.5	49	233.5	150	306332.1	4385432.6
2008	192.8	49	241.8	150	306531.9	4385423.4
2009	164.7	49	213.7	150	306332.1	4385432.6
2010	208.2	49	257.2	150	306432.0	4385428.0

Based on our 2006 through 2010 meteorological data, TEC's highest second-high 24-hour PM₁₀ concentration (208.2 µg/m³) also violates the 24-hour PM₁₀ PSD increment (30 µg/m³). Other modeled years show similar results, as summarized in the following table.

Year of Meteorological Data	Highest 2nd High 24-hr PM₁₀ Concentration (µg/m³)	24-Hr PM₁₀ PSD Increment (µg/m³)	Easting Coordinate (meters)	Northing Coordinate (meters)
2006	164.9	30	306432.0	4385428.0
2007	184.5	30	306332.1	4385432.6
2008	192.8	30	306531.9	4385423.4
2009	164.7	30	306332.1	4385432.6

2010	208.2	30	306432.0	4385428.0
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F. REVISED MODELING RESULTS, USING CORRECTED PM_{2.5} EMISSION RATES, EXCEED THE 24-HOUR PM_{2.5} NAAQS

We obtained the Applicant’s PM_{2.5} emissions as modeled in support of their permit application, and made the following corrections to emission rates:

Source Term (modeled as volume source)	Corrected PM _{2.5} Emissions (g/s)
Active Storage Dome or Inactive Pile Conveyor Loadout (modeled as TP1)	0.0232
Stackout Conveyor #3 to Inactive Pile Lowering Well (modeled as TP2)	0.0232
Inactive Pile Chain Reclaimer to Conveyor #4B (modeled as TP3)	0.0082
Inactive Coal Pile (modeled as PIL1)	0.1454

The basis for these corrected emissions is discussed infra.

We remodeled the Applicant’s PM_{2.5} emissions, with the above revisions, using USEPA’s AERMOD air dispersion model. In addition, we removed all of the non-TEC PM_{2.5} emission sources from our modeling analyses. Thus our PM_{2.5} modeling results are due solely to the proposed TEC project emissions.

We modeled two meteorological data sets: The Applicant’s 2003 through 2007 data and our 2006 through 2010 data using one-minute ASOS winds. For our PM_{2.5} modeling analysis we used the same background 24-hour PM_{2.5} concentration used by the Applicant (28 µg/m³).⁴¹⁴

Using the Applicant’s 2003 through 2007 meteorological data, TEC’s corrected PM_{2.5} emissions result in a 19.8 µg/m³ five-year average highest 24-hour air concentration. When added to the background concentration (28 µg/m³), the total 24-hour PM₁₀ concentration is 47.8 µg/m³. This is a violation of the 24-hour PM_{2.5} NAAQS, as shown in the following table.

2003 -- 2007					
Average Highest 24-Hr PM _{2.5} Concentration (µg/m ³)	Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	24-Hr PM _{2.5} NAAQS (µg/m ³)	Easting Coordinate (meters)	Northing Coordinate (meters)
19.8	28	47.8	35	306531.9	4385423.4

Using our 2006 through 2010 meteorological data developed from one-minute ASOS winds, TEC’s corrected PM_{2.5} emissions result in a 28.3 µg/m³ five-year average highest 24-hour

⁴¹⁴ Modeling Report, p. 5-7.

air concentration. When added to the background concentration ($28 \mu\text{g}/\text{m}^3$), the total 24-hour PM_{10} concentration is $56.3 \mu\text{g}/\text{m}^3$. This is a violation of the 24-hour $\text{PM}_{2.5}$ NAAQS, as shown in the following table.

2006 -- 2010					
Average Highest 24-Hr $\text{PM}_{2.5}$ Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	24-Hr $\text{PM}_{2.5}$ NAAQS ($\mu\text{g}/\text{m}^3$)	Easting Coordinate (meters)	Northing Coordinate (meters)
28.3	28	56.3	35	306531.9	4385423.4

G. REVISED MODELING RESULTS, USING CORRECTED FLARE SO_2 EMISSION RATES, EXCEED THE ONE-HOUR SO_2 NAAQS

The one-hour SO_2 NAAQS takes the form of a three-year average of the 99th-percentile of the annual distribution of daily maximum one-hour concentrations, which cannot exceed 75 ppb.⁴¹⁵ Compliance with this standard is verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu\text{g}/\text{m}^3$. The one-hour SO_2 NAAQS of 75 ppb equals $196.2 \mu\text{g}/\text{m}^3$, and this is the value we used for determining whether TEC's one-hour SO_2 impacts exceed the NAAQS.⁴¹⁶ The 99th-percentile of the annual distribution of daily maximum one-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

TEC's project-specific one-hour SO_2 ambient air impacts (highest-fourth-high) are based on the 99th percentile of the annual distribution of daily maximum one-hour concentrations averaged across the five years of modeled meteorological data. The total concentration values are the sum of TEC's air impacts and the same 99th-percentile background SO_2 concentrations used by the Applicant ($49.8 \mu\text{g}/\text{m}^3$).⁴¹⁷

We obtained the Applicant's SO_2 emissions as modeled in support of its permit application, and revised the maximum hourly SO_2 flaring emissions. We developed two revised maximum hourly SO_2 flaring emissions, ranging from 12,048 to 20,080 lb/hr. The basis for these revised maximum hourly SO_2 flaring emissions is discussed infra. We remodeled the lower of the two revised hourly SO_2 flaring emissions (12,048 lbs/hr) as 1518.05 grams/sec. We remodeled the higher of the two revised hourly SO_2 flaring emissions (20,080 lbs/hr) as 2530.08 grams/sec.

We remodeled the Applicant's SO_2 emissions, with the above revisions, using USEPA's AERMOD air dispersion model. In addition, we removed all of the non-TEC emission sources from our modeling analyses. Thus our modeling results are due solely to the proposed TEC

⁴¹⁵ U.S.EPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010, attached as Ex. 143, appwso2.pdf.

⁴¹⁶ The ppb to $\mu\text{g}/\text{m}^3$ conversion is found in the source code to AERMOD v. 11103, subroutine Modules. The conversion calculation is $75/0.3823 = 196.2 \mu\text{g}/\text{m}^3$.

⁴¹⁷ Modeling Report, p. 5-6.

project emissions. We also modeled the revised SO₂ emissions using two meteorological data sets: The Applicant's 2003 through 2007 data and our 2006 through 2010 data using one-minute ASOS winds. Thus our one-hour SO₂ air quality modeling analyses consists of four scenarios: two meteorological data sets each modeled with two revised maximum hourly SO₂ flaring emission rates.

Scenario 1: Revised maximum hourly SO₂ flaring emission rate of 12,048 lbs/hr, modeled with the Applicant's 2003 through 2007 meteorological data.

For this scenario, TEC's emissions result in a 165.4 µg/m³ five-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (49.8 µg/m³), the total one-hour SO₂ concentration is 215.2 µg/m³. This is a violation of the one-hour SO₂ NAAQS. These results are summarized in the following table.

2003 - 2007 5-Yr Average 4th Highest One-Hr SO₂ Concentration (µg/m³)					
SO₂ Concentration (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	One-Hr SO₂ NAAQS (µg/m³)	Easting Coordinate (meters)	Northing Coordinate (meters)
165.4	49.8	215.2	196.2	305702.7	4386601.7

Scenario 2: Revised maximum hourly SO₂ flaring emission rate of 20,080 lbs/hr, modeled with the Applicant's 2003 through 2007 meteorological data.

For this scenario, TEC's emissions result in a 272.8 µg/m³ five-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (49.8 µg/m³), the total one-hour SO₂ concentration is 322.6 µg/m³. This is a violation of the one-hour SO₂ NAAQS, with or without adding the background concentration. These results are summarized in the following table.

2003 -- 2007 5-Yr Average 4th Highest One-Hr SO₂ Concentration (µg/m³)					
SO₂ Concentration (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	One-Hr SO₂ NAAQS (µg/m³)	Easting Coordinate (meters)	Northing Coordinate (meters)
272.8	49.8	322.6	196.2	305702.7	4386601.7

Scenario 3: Revised maximum hourly SO₂ flaring emission rate of 12,048 lbs/hr, modeled with our 2006 through 2010 meteorological data developed from one-minute ASOS winds.

For this scenario, TEC's emissions result in a 180.7 µg/m³ five-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (49.8 µg/m³), the total one-hour SO₂ concentration is 230.5 µg/m³. This is a

violation of the one-hour SO₂ NAAQS. These results are summarized in the following table.

2006 - 2010 5-Yr Average 4th Highest One-Hr SO₂ Concentration (µg/m³)					
Background Concentration (µg/m³)	Total Concentration (µg/m³)	One-Hr SO₂ NAAQS (µg/m³)	Easting Coordinate (meters)	Northing Coordinate (meters)	
49.8	230.5	196.2	306802.7	4384201.6	180.7

Scenario 4: Revised maximum hourly SO₂ flaring emission rate of 20,080 lbs/hr, modeled with our 2006 through 2010 meteorological data developed from one-minute ASOS winds.

For this scenario, TEC's emissions result in a 300.8 µg/m³ five-year average fourth-highest daily maximum one-hour SO₂ concentration. When added to the background concentration (49.8 µg/m³), the total one-hour SO₂ concentration is 350.6 µg/m³. This is a violation of the one-hour SO₂ NAAQS, with or without adding the background concentration. These results are summarized in the following table.

2006 - 2010 5-Yr Average 4th Highest One-Hr SO₂ Concentration (µg/m³)					
Background Concentration (µg/m³)	Total Concentration (µg/m³)	One-Hr SO₂ NAAQS (µg/m³)	Easting Coordinate (meters)	Northing Coordinate (meters)	
49.8	350.6	196.2	306802.7	4384201.6	300.8

Each of our four modeled SO₂ flaring emission scenarios show that the proposed TEC project will cause violations of the one-hour SO₂ NAAQS. IEPA should not issue TEC's permit until specific conditions exist that ensure SO₂ flaring emissions will not cause violations of the one-hour SO₂ NAAQS.

H. TEC HAS FAILED TO VERIFY COMPLIANCE WITH THE OZONE NAAQS

Single-source modeling for ozone was one of the more important topics discussed at the recently-held Ninth Conference on Air Quality Modeling.⁴¹⁸ With respect to ozone, the revised 0.075 ppm 8-hour NAAQS brings additional areas into nonattainment status or in danger of becoming nonattainment, heightening the need for rigorous analysis of ozone impacts from major emission sources. This situation should be of paramount importance to IEPA, as numerous areas in Illinois are exceeding the 0.075 ppm 8-hour NAAQS.⁴¹⁹ In Illinois, the Chicago Metropolitan, Metro East, North Illinois, West-Central Illinois, East Central, and

⁴¹⁸ <http://www.epa.gov/scram001/9thmodconfpres.htm>

⁴¹⁹ <http://www.epa.state.il.us/air/ozone/exceedances.html>

Southeast areas all exceed the 0.075 ppm 8-hour NAAQS.⁴²⁰ Significantly large areas to the northeast and southwest of the proposed project site are currently nonattainment for the ozone NAAQS.⁴²¹

Rather than using single-source air dispersion modeling for their ozone analysis, TEC assesses ozone impacts from their proposed project using a simple set of screening tables. Specifically, Section 3.4 of Applicant's Modeling Report relies solely on the simple and inappropriate "Scheffe Tables" for assessing ozone impacts from the project's major stationary source emissions.⁴²² IEPA should have rejected this insufficient analysis, yet they did not.⁴²³

Regarding the applicability of these tables, Dr. Richard Scheffe (the developer of the tables used by the Applicant) has issued a memo clearly stating that the method is, and has always been, inadequate for assessing project ozone impacts. Dr. Scheffe explains:

I developed the screening tables in 1988 as a screening test to estimate the contribution to ambient ozone associated with increased non-methane organic carbon (NMOC) emissions arising from new or modified point sources. The tables never achieved a level of EPA certification associated with EPA guideline models and consequently were not endorsed by the Agency. After publication (non-peer reviewed literature) of the tables in 1989, the American Petroleum Institute enlisted renowned atmospheric modeling experts, Drs. John Seinfeld and Panos Georgopoulos of the California Institute of Technology, to review the technique. Based on their input and our own analysis, the EPA decided at that time that the tables did not adhere to an adequate level of scientific credibility to be recommended for their intended purpose.

Ozone science has advanced markedly since 1988 with substantial improvements in the characterization of emissions, meteorological, and atmospheric chemistry processes, paralleling an equivalent improvement in computational processing capability, all of which constitute the principal features of a modeling framework. As a result, the Scheffe method, which was deemed "not adequate" in 1989, would be even less adequate today.⁴²⁴

Given the complex nature of TEC's NO_x and VOC emissions and resulting ozone concentrations, there is no justification for IEPA to rely on the Scheffe Point Source Screening Tables for verifying compliance with the new 8-hour ozone NAAQS of 0.075 ppm. The U.S. EPA agrees with Dr. Scheffe that given the current state of the art, this technique is inappropriate for assessing ozone impacts. From U.S. EPA's analyses regarding *Approval and Promulgation*

⁴²⁰ *Id.*

⁴²¹ <http://www.epa.gov/oaqps001/greenbk/map8hr.html>

⁴²² Modeling Report, pp. 3-13 – 3-15.

⁴²³ Project Summary, p. 14.

⁴²⁴ Memo from Dr. Richard Scheffe to Ms. Abigail Dillen (July 28, 2006), attached as Ex. 129, Scheffe Memo 7_28_06.pdf.

of Implementation Plans; Kentucky; 110(a)(1) and (2) Infrastructure Requirements for the 1997 8-Hour Ozone National Ambient Air Quality Standards:

EPA agrees that States should not be using inappropriate analytical tools in this context. For example, the Commenter's Exhibit 14 does discuss the inappropriateness of using a screening technique referred to as the "Scheffe Tables." The Commenter is correct that the use of "Scheffe Tables" and other particular screening techniques, which involve ratios of nitrogen oxides (NOx) to volatile organic compounds (VOC) that do not consider the impact of biogenic emissions, or that use of other outdated or irrelevant modeling is inappropriate to evaluate a single source's ozone impacts on an air quality control region. More scientifically appropriate screening and refined tools are available and should be considered for use.⁴²⁵

It is important to note that facilities in U.S. EPA Region VI have recently used photochemical grid models for ozone impact assessments. For example, two recently proposed major source facilities prepared ozone impact analyses using CAMx and associated SIP modeling episodes. The proposed facilities are NRG Limestone 3, a coal-fired power plant in Texas, and Nucor Steel Louisiana. There is no reason why IEPA should allow TEC to use a clearly inadequate ozone assessment, when Texas and Louisiana are requiring state-of-the-art photochemical grid models.

Moreover, TEC's VOC emissions are greatly under-estimated, thus further invalidating the Applicant's simple "back-of-the-envelope" ozone analysis. *See* discussion infra regarding underestimated VOC emissions.

Clearly, the Applicant failed to verify compliance with the 8-hour ozone NAAQS of 0.075 ppm. IEPA must deny Tenaska's permit application until appropriate air dispersion modeling is performed that demonstrates compliance with this standard.

VII. ENFORCEABILITY

A. THE CLEAN AIR ACT REQUIRES THE PRACTICAL ENFORCEABILITY OF PERMIT LIMITS

The Clean Air Act requires permits be practically enforceable. The U.S. EPA has emphasized that point. "Practicable enforceability" means that a permit's provisions must specify:

- (1) A technically-accurate limitation and the source subject to the limitation;
- (2) the time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and
- (3) the method to determine compliance including appropriate monitoring, recordkeeping, and reporting.

⁴²⁵ Federal Register, Vol. 76, No. 134, July 13, 2011, p. 41097.

73 Fed. Reg. 1570, 1573 (Jan. 9, 2008).

The NSR Manual similarly provides:

The emissions limits must be included in the proposed permit submitted for public comment, as well as the final permit. BACT emission limits or conditions must be met on a continual basis at all levels of operation (*e.g.*, limits written in pounds/MMBtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements).

Consequently, the permit must:

- be able to show compliance or noncompliance (*i.e.*, through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and
- specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source.

NSR Manual at B.56. Since the PSD Permit terms and conditions will also eventually be incorporated as part of the TEC's federal Title V operating permit, known as a Federally Enforceable State Operating Permit ("FESOP") at the state level, law and guidance on enforceability in the Title V context also are instructive.

Pursuant to the Clean Air Act, Title V permits are to include, among other conditions, "enforceable emission limitations and standards, ... and such other conditions as are necessary to assure compliance with applicable requirements of [the Act], including the requirements of the applicable implementation plan." 42 U.S.C. § 7661c(a) (emphasis added). U.S. EPA policy requires Title V permits to be "enforceable as a practical matter."⁴²⁶ Thus, to be enforceable, the permit must create mandatory obligations (standards, time periods, methods). Specifically, a permit condition must: (1) provide a clear explanation of how the actual limitation or requirement applies to the facility; and (2) make it possible for the [state agency], the U.S. EPA, and citizens to determine whether the facility is complying with the condition. *See, e.g., Sierra Club v. Ga. Power Co.*, 365 F. Supp. 2d 1297, 1308 (D. Ga. 2004) (citing *Sierra Club v. Public Serv. Co.*, 894 F. Supp. 1455, 1460 (D. Colo. 1995)). Title V permits must contain monitoring and reporting requirements to allow citizen enforcement, in addition to the ability of State and Federal Regulators' ability to enforce the Title V permits). The U.S. EPA has provided examples of permit conditions that are not enforceable as a practical matter in a letter to the Ohio Environmental Protection Agency ("OEPA") setting out deficiencies in Ohio's Title V program. In that letter, EPA explained that, "In addition to implementing appropriate compliance methods,

⁴²⁶ See U.S. Environmental Protection Agency, Region 9, Title V Permit Review Guidelines: Practical Enforceability, September 9, 1999, (hereafter "Region 9 Guidelines"), attached as Ex. 147.

the monitoring, recordkeeping, and reporting requirements must be written in sufficient detail to allow *no room for interpretation or ambiguity in meaning*. Requirements that are imprecise or unclear make compliance assurance impossible.”⁴²⁷

Similarly, U.S. EPA policy explains that for a permit condition to be enforceable, the permit must leave no doubt as to exactly what the facility must do to comply with the condition. *Region 9 Guidelines*, at III-55.

A permit is enforceable as a practical matter (or practically enforceable) if permit conditions establish a clear legal obligation for the source [and] allow compliance to be verified. Providing the source with clear information goes beyond identifying the applicable requirement. It is also important that permit conditions be unambiguous and do not contain language which may intentionally or unintentionally prevent enforcement.

Id. The “practical enforceability” requirement is necessary “to assure the public’s and EPA’s ability to enforce the title V permit is maintained, and to clarify for the title V source its obligations under the permit.” *Id.* at III-56. Citizens do not have the powers at their disposal that agencies have (i.e., the power to conduct an inspection, the power to require the submittal of records or documents by the permittee, or the power to reopen a permit). As a result, the permit must be self-contained (include all terms, definitions and conditions that are necessary to enforce the permit) and must be clear in order to be practically enforceable. *See generally, id.* at III-57 to III-62.

B. GENERAL ISSUES

1. Findings Are Not Enforceable Permit Conditions

In issuing PSD permits, state agencies and applicants must identify a host of parameters, including the sulfur and ash content of the fuel, to determine emission limitations, compliance with PSD increments and NAAQS. As is always the case, all of the parameters used in making these assessments do not necessarily become part of the federally enforceable terms of the facility’s permits. It is key that essential parameters that will ultimately impact the facilities ability to emit at a certain level or comply with NAAQS and PSD increments must be included in the enforceable permit conditions, in order for those provisions to be practically enforceable.

The Draft Permit for TEC is 138 pages long. While most of these pages contain enforceable permit conditions (*see, e.g.*, Section 3, Source Wide Permit Conditions, Section 4, Unit Specific Conditions for Specific Emission Units), not all of the parameters discussed in these 138 pages are enforceable permit conditions. Most notably, Section 1, The Findings for the Revised Permit, are probably not enforceable permit conditions as it is a narrative description by the agency about why it is issuing this permit. Some key assumptions that would impact the

⁴²⁷ *See* Letter from Bharat Mathur, U.S. Environmental Protection Agency, Region 5, to Robert F. Hodanbosi, Ohio Environmental Protection Agency, November 21, 2001, attached as Ex. 131.

amount of pollution emitted by TEC are contained only in this section. IEPA should revise the permit to include these parameters in the enforceable permit conditions.

The Draft Permit includes nine “Findings for the Revised Permit.” These include findings on the amount of syngas that will be produced (64 million standard cubic feet), the power block nominal net electrical out (602 MW), and the design coal supply for the plant.⁴²⁸ The Draft Permit at p. 3 states, for example:

“The design coal supply for the plant would be Illinois Basin coal nominally containing 4.4 percent sulfur by weight and 11,300 Btu per pound as received at the plant. The design feed rate of coal to the gasification block would be 212 tons of coal per hour.”

This is not a permit condition but rather a “finding.” There is not a corresponding permit condition that limits the Applicant to using the coal that was used as the basis of the emission estimates, which in turn were used to demonstrate compliance with NAAQS and to determine major source status. The HAP emission calculations, for example, were based on a specific Illinois Basin coal, from the Herrin seam.⁴²⁹ Other coals would have different amounts of HAPs. Information found elsewhere shows that the use of Herrin seam coal is by no means a given but that the Applicant also considers using coal from the Springfield seam.⁴³⁰

Similarly, the SO₂ emissions were based on a coal containing 3.75% sulfur, but the subject finding indicates coal nominally containing 4.4% sulfur would be used. This would significantly increase SO₂ emissions and cause violations of the 1-hr SO₂ NAAQS. Finally, as discussed below, the Permit does not require any monitoring to discover violations of emission limits established with the coal assumed in the Application. Thus, if the Applicant chooses to use a higher sulfur coal, or a coal containing more HAPs, it would not be discovered.

Because each type of coal or coal blend can have different effects on the facility’s emissions and hence air quality impacts and major source status of the facility, there must be an enforceable permit condition limiting the amount of sulfur and HAPs in the coal feed or else the Applicant’s emission estimates and proposed permit limits are meaningless.

2. The Assumptions in Emission Calculations Are Not Enforceable

The Application estimated emissions from many sources, including the flares; feedstock and bulk material handling, drying and storage; equipment components; cooling towers; and roadways and other open areas using a wide range of assumptions, including throughputs, silt

⁴²⁸ Draft Permit, p. 3.

⁴²⁹ Ap., p. 12-2 (“... metallic HAP emissions from raw syngas, sweet syngas, and off-spec SNG combustion in the flare were calculated based on emission factors derived from Herrin coal metals data...”) and Table C-22-.2, p. C-82.

⁴³⁰ Illinois Commerce Division, Taylorville Energy Center Facility Cost Report, Exhibit 6.0, Wood Mackenzie Study, The Delivered Price of Coal to the Taylorville Energy Center, p. 9; <http://www.icc.illinois.gov/downloads/public/en/Exhibit%206.0%20-%20Wood%20Mackenzie%20Study%20The%20Delivered%20Price%20of%20Coal%20to%20the%20Taylorville%20Energy%20Center.pdf>, attached as Ex. 60.

content, number and type of vehicles, miles traveled, areas, concentrations, flow rates, and control efficiencies, etc. The resulting emissions were used in air dispersion models to demonstrate compliance with PSD increments and NAAQS.

However, the Draft Permit does not require any actual monitoring to determine compliance with these emission limits, arguing monitoring is not feasible and thus a work practice standard applies. However, the variables that were used to estimate the emissions can be limited to those assumed in the calculations and measured. Silt content, for example, a key input to all of the material handling emissions, is easily measured using the method in AP-42. The throughput for the various operations can be limited in the Permit and recorded. The resulting data can be used to estimate emissions using the same procedures used the Application.

3. Plans

The IEPA cannot issue the Permit because it does not incorporate malfunction, startup/shutdown, and quality control plans into the permit which the agency relied upon to determine that the source will meet applicable requirements or provide these plans for public comment. The Draft Permit requires that a number of plans be developed in the future to satisfy BACT. These include Startup, Shutdown, and Malfunction Plan for emission units (Conditions 4.1.2-1.c and 4.1.5-2); Flare Minimization Plan (Condition 4.1.5-3); a Feedstock Management Plan (Condition 4.1.5-4); a Startup, Shutdown and Malfunction Plan for the Power Block (Condition 4.2.5-2); a Fugitive Dust Control Program for material handling emissions (Condition 4.3.5.e); Haul Road Operating Plan (Condition 4.11.5). These plans will be developed in the future, outside of the PSD review process which will preclude public review.

Throughout the permit, IEPA relies on the SSM, minimization, and emission control plans to assure compliance with applicable standards. IEPA does not merely require the plans to be submitted, but relies on the plans as the basis for finding that the plant will comply with applicable requirements and to define terms in the permit. Because IEPA is relying on these plans to ensure compliance and to define permit terms, the Plans must be provided in the application. 40 C.F.R. § 70.5(a)(2) (a complete application must contain sufficient information to determine all applicable requirements), 70.5(c) (application cannot “omit information needed to determine the applicability of, or impose, any applicable requirement...”), 70.5(c)(3)(vi) (application must include any “work practice standards”). The plans were not included with the application, or the public review documents. The public had no opportunity to review the plans to determine whether they were sufficient to ensure compliance, or to determine the definition of permit terms. This is unlawful.

In addition, because compliance with the plans constitutes a Permit requirement, the plans must be subject to public notice and comment. The public cannot comment on the sufficiency of the Permit, which incorporate, reference, or otherwise rely on the plans, when the plans were not part of the permit record and will not even be created until after the permit is issued. 40 C.F.R. § 70.7(h); *see e.g., In re RockGen Energy Center*, 8 E.A.D. at 553-54 (remanding permit requirement for a startup/shutdown plan that was not subject to public notice and review); *Waterkeeper Alliance v. EPA*, 399 F.3d 486, 503-04 (2nd Cir. 2005) (invalidating

EPA regulation that allowed Nutrient Management Plans to be submitted after public comment and after a NPDES permit was issued).

C. FLARE CONDITIONS ARE NOT ENFORCEABLE

1. Flare Sulfur Conversion Efficiency Not Enforceable.

The SO₂ flare emission calculations assume that 98% of the sulfur in the flared gases is converted to SO₂. If a larger amount of the sulfur were converted to SO₂, the 1-hour SO₂ NAAQS could be exceeded. The Draft Permit does not contain any limit on the sulfur to SO₂ conversion efficiency of the flare nor any method to determine if it is met.

2. Flare Destruction Efficiencies Are Not Enforceable.

The emission calculations assume destruction and removal efficiencies of at least 98% for CO and VOM and at least 99% for methanol and methane. The Draft Permit establishes these as limits. Condition 4.1.2-1a(v). However, it does not require any method to assure these removal efficiencies are achieved in practice. Conditions 4.1.7-1 and 4.1.8-2.

These can be demonstrated using a combination of three methods. First, the Permit should require that the flare vendor supply a guarantee for the subject efficiencies and supply the guarantee to the IEPA. Second, the Permit should be modified to require video monitoring of the flare, as currently required in SJVAPCD Rule 4311 and that actions be taken to improve combustion efficiency when anomalous conditions are observed, e.g., flame detachment from the flare stack, soot, etc. Third, it is feasible to measure the combustion efficiency using various remote sensing methods such as passive FTIR, which has been required by the EPA in other situations.⁴³¹

3. Results of Flare BACT Analysis Not Required as Enforceable Condition

The BACT analysis in the Application identified a specific operating procedure to reduce emissions during a cold plant startup by 60%, from 170,000 lb/event to 72,000 lb/event. This procedure involves shifting raw syngas forward into the control system as quickly as possible.⁴³² The planned startup and shutdown emission calculations assumed this procedure is used. See Comments infra. The IEPA Project Summary does not mention it, and it is not required in the Draft Permit to satisfy BACT. Condition 4.1.2-1. Thus, the BACT determination is not enforceable.

⁴³¹ Marathon Petroleum Company, Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR, Final Report, May 2010, attached as Ex. 133; Thomas R. Blackwood, An Evaluation of Flare Combustion Efficiency Using Open-Path Fourier Transform Infrared Technology, *J. Air & Waste Manage. Assoc.*, v. 50, Oct. 2000, pp. 1714-1722, attached as Ex. 134.

⁴³² Ap., p. 6-6.

The maximum hourly SO₂ emission rate set for the flare (Condition 4.1.6.b) was calculated based on this BACT assumption. However, as discussed *infra*, the Draft Permit does not contain adequate monitoring to determine if this emission rate is achieved. Therefore, the maximum hourly emission rates using in the PSD increment and NAAQS modeling are not enforceable as a practical matter.

4. Hourly Flare Limits Are Not Enforceable

The Draft Permit sets hourly and annual emission limits on the flare in Condition 4.1.6.b. These limits are not enforceable for the reasons set out below.

a. Hourly SO₂ Limit

The permit sets a limit of 9,036 lb/hr on SO₂ emissions from the flare. This value was calculated from material balances and assumptions, such as sulfur content and duration of raw syngas flaring, which are not disclosed in the Permit record. Exceedances of this limit would never be discovered because the Permit does not require adequate testing.

First, the Draft Permit requires CEMS to measure total flow of process gas sent to the flare and the H₂S and CO content of this gas. Condition 4.1.8-2.a. This is not enough information to determine the 1-hour SO₂ emission rate.

The SO₂ emissions from the flare arise from the combustion of two sulfur containing gases, H₂S and COS. The Permit does not require monitoring of COS, which excludes about 13% of the SO₂.

Second, the Permit is silent on what one does with the measurements of flow rate and H₂S to come up with an hourly SO₂ emission rate. The CEMS data must be converted to pounds per hour of SO₂ and multiplied by a conversion efficiency to yield flare SO₂ emissions. The calculations that yielded the 1-hour limit of 9,036 lb/hr assumed a 98% conversion efficiency. See Comments *infra*. As noted above, the Permit does not require this as a limit.

The CEMS measurements alone are not adequate to determine hourly SO₂ emissions at the flare, unless it is assumed that 100% of the sulfur in the gases sent to flare are converted to SO₂. This is the usual assumption,⁴³³ but here, the calculations that led to the one-hour limit of 9,036 lb/hr assumed only 98%. A higher conversion efficiency would result in violations of NAAQS.

Thus, the Permit does not assure compliance with the 1-hour SO₂ limit as a major component of SO₂ is omitted from monitoring, no method is provided for making the calculation, and no limit on sulfur to SO₂ conversion efficiency is contained in the Permit. Thus, exceedances of the limit would never be discovered and violations of the 1-hour SO₂ NAAQS would go undiscovered.

⁴³³ See, e.g., Power Holding of Illinois, LLC, Flare Emissions - Evaluation, November 5, 2008, p. 3 (“When going thru the Flare:... H₂S and COS all go to SO₂.”), attached as Ex. 1.

b. Other Hourly Limits

The Draft Permit also sets hourly limits on VOM and PM. Condition 4.1.6.b. However, the Permit does not require any routine monitoring of these pollutants in gases sent to the flare nor any indication of how compliance with these limits would be determined. The Draft Permit does require that a file be maintained that contains emission factors used to calculate emissions (Condition 4.1.10-2), but no method on how these emission factors would be used to determine compliance with maximum annual limits. Thus, these annual limits are unenforceable.

c. Annual Flare Limits Are Unenforceable

The Draft Permit sets annual limits in tons per year on SO₂, NO_x, CO, VOM, PM, COS, and CO_{2e}. Condition 4.1.6.b. There are two major problems with these limits.

First, as explained for the hourly limits, the Permit does not require any routine monitoring of most of these pollutants in gases sent to the flare (CO and H₂S are monitored) nor any indication of how compliance with these limits would be determined. The Draft Permit does require that a file be maintained that contains emission factors used to calculate emissions of VOM, PM, and other pollutants (Condition 4.1.10-2), but no prescription for what those emission limits can be and how they might be used to determine compliance with maximum 1-hour emission limits. Thus, these limits are unenforceable.

Second, these annual limits only take effect one year after the shakedown of the gasification block is complete. This means no limits at all are in place for COS and CO_{2e} for over a year after startup, and no annual limit for SO₂, NO_x, CO, VOM, and PM.

D. **POWER BLOCK CONDITIONS ARE NOT ENFORCEABLE**

1. Power Block Startup and Shutdown

The Draft Permit in Section 4.2.2 exempts startups, shutdowns, and malfunctions from BACT emission limits for NO_x, CO, VOM, and CO₂. These are addressed in Condition 4.2.2(d), which refers to separate limits specified in lbs/event in Condition 4.2.6(a) (Attachment 1, Table I). Attachment 1, Table I sets separate emission limits for NO_x, CO, VOM, and CO₂ for cold starts, warm starts, hot starts, and shutdowns, but does not set any limits at all for malfunctions. These startup and shutdown limits are not enforceable.

First, the Draft Permit does not define cold start, warm start, and hot start, making application of these limits to any given event ambiguous. The definitions in the Application at 7-15 should be incorporated into the Permit. Further, each of these types of events occurs at different frequencies and lasts for different durations, and therefore has different emission profiles, which have the potential of affecting compliance with 1-hour NAAQS and PSD increments. The Draft Permit does not identify or sufficiently limit the frequencies of cold starts, warm starts, and hot starts.

Second, the Draft Permit does not require any monitoring to determine compliance with these startup and shutdown limits. Rather, Condition 4.2.2(d) states that compliance is to be “determined based on engineering analysis and calculations.” The Draft Permit and supporting record are silent as to what engineering analysis and calculations are required by Condition 4.2.2(d), preventing any review.

Condition 4.2.7(a)(i)(A), emission testing, notes that “[i]n addition, the Permittee may also perform measurements to evaluate emissions at other loads and operating conditions [other than at maximum production],” making it clear that testing is at the discretion of the Applicant. The Application at p. 7-14, on the other hand, states that “[c]ompliance with these limits will be determined via CEMS for NOx and CO.”

Third, neither the Application, the Draft Permit, nor the supporting record mentions any testing for VOM. The Application at p. 7-14, for example, states “[f]or VOM, compliance will be determined by recordkeeping and manufacturer estimates.” This is circular and does not require that the manufacturer estimates ever be confirmed. Thus, compliance is never determined for VOM emissions during SSM events, rendering the limits in Attachment 1, Table I unenforceable.

Fourth, the Draft Permit includes annual limits for the combustion turbines in tons per year. The Application suggests that these are “an alternative to separate short-term limits” as they include startups and shutdowns.⁴³⁴ However, they contain the same problems discussed above, namely, no requirement to actually measure the startup and shutdown emissions to include in the tally for the annual limits. Thus, they do not cure the defect of no monitoring.

2. Power Block Malfunctions

Malfunctions are exempted from BACT requirements, but are not covered by separate limits as required by the Clean Air Act. Because the Best Available Control Technology requirement is an “emission limitation,” *see* 42 U.S.C. § 7479(3), App. E, PSD permitted power plants must always comply with BACT; thus an agency cannot exempt start up, shut down, or malfunction events. Emissions limitations are designed to “limit[] the quantity, rate, or concentration of emissions of air pollutants on a *continuous* basis.” 42 U.S.C. § 7602(k), App. F (emphasis added). As a result, although emission limits may vary to reflect special conditions during malfunction and atypical performance periods, an agency may not waive them. *See In re Indeck-Elwood, LLC*, PSD Appeal No. 03-04, slip op. at 66, 2006 WL 3073109 (EAB 2006) (“It is well established that BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown.”); *see also In re Rockgen Energy Center*, 8 E.A.D. 536, 553, 1999 WL 673224 (EAB 1999) (quoting EPA guidance for the proposition that “[s]tartup and shutdown of process equipment are part of the normal operation of a source Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods”); *In re: Knauff Fiber Glass, GMBH*, 8 E.A.D. 121, PSD Permit No. 97-PO-06 (Feb. 04, 1999) (“There are no exceptions to the permit limits for periods of equipment malfunction, breakdown, or upset.”) 65 Fed. Reg. 70,792, 70,793 (Nov. 28,

⁴³⁴ Ap., v. 1, p. 7-14.

2000) (EPA rulemaking “reiterat[ing] that, under the Act, all excess emissions during starts up, shuts down, or malfunctions episodes are violations of applicable emission limitations.”).

Because emission limitations apply at all times, the permit’s standards for start up, shut down, and malfunction periods must still be based on the Best Available Control Technology for the problems encountered during those periods.

Malfunctions in the power block might include, for example, SCR catalyst issues that would require taking the unit offline, HRSG tube leaks, or steam turbine outages. During these periods, gases that would otherwise be treated to high standards and combusted would be flared or vented. The Draft Permit fails to regulate emissions during these events, which is contrary to the law.

E. ROADWAYS AND OPEN AREA CONDITIONS ARE NOT ENFORCEABLE

1. The Results of the BACT Analysis Are Not Required As Enforceable Permit Conditions

For haul roads, the Application concluded that BACT is paving plus washing, sweeping or vacuuming to reduce 90% of the PM, PM₁₀, and PM_{2.5}. For open areas, the Application concluded that BACT is dust suppression to reduce 90% of the PM, PM₁₀, and PM_{2.5}.⁴³⁵ The Draft Permit does not require 90% reduction in PM, PM₁₀ or PM_{2.5} emissions, but rather sets an opacity limit of 10% without explaining where it came from or how 10% opacity guarantees that dust suppression will be used to reduce emissions by 90% to achieve the emission rates in lb/hr that were included in the air quality modeling.⁴³⁶

2. The Modeled Emissions Are Not Enforceable

The Application estimated the emissions that would result from hauling and handling coal, slag, liquid sulfur, filter cake, ZLD solids, and methanol, among others. These emissions were included in the air quality modeling to demonstrate compliance with PM₁₀ and PM_{2.5} ambient air quality standards. The emission calculations were based on a large number of assumptions which must be realized in practice to assure that standards are not exceeded. While it is difficult to directly measure the PM, PM₁₀, and PM_{2.5} emissions from haul roads, it is feasible and facile to measure the input assumptions used in these calculations to verify the emission calculations. These verifiable assumptions include roadway silt content, number and type of vehicles, vehicle weights, distances travelled, and maximum daily throughputs of various hauled materials. The Draft Permit does not limit any of these inputs. Thus, the emissions included in the air quality analysis are not enforceable and the analyses cannot be used to conclude that the project would not have any adverse air quality impacts.

F. MATERIAL HANDLING CONDITIONS ARE NOT ENFORCEABLE

⁴³⁵ Ap., v.1, pp. 11-2 to 11-3.

⁴³⁶ Draft Permit, Cond. 4.11.2.

1. Storage Pile (PIL1-3) and Transfer Point Emissions (TP1-3)

a. Emission Limits

The modeling analysis assumes very low, unsupportable and erroneous emissions for PM₁₀ and PM_{2.5} emissions from three transfer points (TP1-3) and inactive storage pile sources (PIL1-3) that are not controlled by a dust collector. Comments infra discussed the errors in these calculations. These emissions were underestimated by over a factor of 30. The Draft Permit contains no mechanism(s) to discover this underestimate.

The conditions in the Draft Permit do not assure that these low emission rates, required to avoid exceeding the 24-hour PM₁₀ and PM_{2.5} increments and NAAQS, are achieved in practice. The emissions that were modeled are not included in the Draft Permit as emission limits. The key inputs used to calculate these emissions are also not stated as Permit conditions or measured: wind speed, silt content, moisture content, and control efficiency. Thus, even a calculation of emissions to demonstrate compliance is not feasible. Compliance with an opacity limit does not assure that the modeled PM₁₀ and PM_{2.5} emissions are achieved in practice.

b. BACT Not Required

The Application concluded that BACT for the transfer points (TP1-3) is wet dust suppression as a work practice standard with compliance based on an opacity level of 10%.⁴³⁷ The Application also concluded that BACT for wind erosion (PIL1) and maintenance transfer (PIL1-3) for the inactive storage pile is wet dust suppression and pile compaction as work practice standards.⁴³⁸

First, the Draft Permit does not require pile compaction, but rather only the implementation and use of control measures that “minimize visible emissions of PM...”⁴³⁹ The phrase “minimize visible emissions” is ambiguous and does not necessarily require the BACT control of compaction.

Second, the BACT control required in the Draft Permit – “wet dust suppression” – is ambiguous.⁴⁴⁰ What does the term “wet dust suppression” mean? Watering only? Does it require chemical suppressants and binders? How frequently must the suppressant be applied to assure the control levels required to protect the NAAQS and PSD increments? Watering only is inconsistent with both the Application and modeling, but is a reasonable interpretation of the Draft Permit language. The estimated PM₁₀ and PM_{2.5} emissions assumed high dust control efficiencies, which require continuous application of chemical suppressant and binder. The Draft Permit lacks any description whatsoever of what is required to achieve the assumed control efficiencies, 50% to 90%, factors such as frequency and amount/type of suppressant applied.

⁴³⁷ Ap., v. 1, p. 8-11.

⁴³⁸ Ap., v. 1, p. 8-18.

⁴³⁹ Draft Permit, Cond. 4.3.5.b.

⁴⁴⁰ Draft Permit, Cond. 4.3.2.d.

Third, the measures that would be implemented to control fugitive emissions will be identified in a plan, which will be submitted later.⁴⁴¹ This violates the public review requirements of the PSD program, preventing public comment.

Fourth, the Draft Permit does not require compliance with 10% opacity at TP2 or TP3. The only opacity monitoring required in the Draft Permit is that pursuant to NSPS Subpart Y.⁴⁴² This provision only applies to TP1.⁴⁴³ Thus, no opacity monitoring is required for TP2 and TP3 or PIL1.

G. EQUIPMENT LEAK CONDITIONS ARE NOT ENFORCEABLE

1. Definitions

The emission calculations assumed very high control efficiencies, typically 97% emission reduction, for certain components controlled by LDAR programs. The Application characterized these components as being “high VOM fraction process streams” or “high VOM and H₂S fraction process streams,” without ever defining these terms.⁴⁴⁴

The Draft Permit adds to the ambiguity by applying LDAR only to unidentified components in triethylene glycol service in the SNG drying process; components in methanol, propylene, and acid gas service within the AGR unit; components in sour gas and acid gas service in the SRU process; and components in methanol and propylene service in miscellaneous minor process areas.⁴⁴⁵ The Draft Permit does not define these terms or identify the subject components on piping and instrumentation diagrams.

Proper identification is required to assure that the reductions assumed in the emission calculations (and used as the basis for eliminating more effective controls as BACT) are actually realized. How much methanol or propylene must be in the stream to qualify as in methanol or propylene service? What are sour gas and acid gas? How much H₂S, for example, must be present in a process stream to render it “sour” or to classify it as “acid gas?”

The Permit should be revised to require an explicit inventory of the components subject to LDAR, *i.e.*, location on P&ID that is tied to the assumptions in the emission calculations to assure that the reductions assumed in the emission calculations are achieved. The Permit also should be modified to define all terms used in establishing the LDAR program to eliminate ambiguity.

2. LDAR Fails to Cover All Pollutants

⁴⁴¹ Draft Permit, Cond. 4.3.5.d.

⁴⁴² Draft Permit, Cond. 4.3.3-1.c.

⁴⁴³ Ap., v. 1, p. 4-12, Table 4-2.

⁴⁴⁴ See Ap., v. 1, Appx. C, Tables C-24.2, C-25.2, C-26.2, and C-27.2 and v. 3, Appx. A, Tables A-16.2 and A-17.2.

⁴⁴⁵ Draft Permit, Cond. 4.9.2.a(i).

Equipment leaks contain many regulated pollutants, including VOCs, CO, H₂S, COS, CH₄, and CO₂, among others. However, the LDAR requirement, which is assumed in the emission calculations to control all of them, applies only to VOM emissions.⁴⁴⁶ The term “VOM” is not defined anywhere in the Draft Permit, but presumably is volatile organic material, or something similar. This term is ambiguous and must be defined in the Permit to assure enforceability.

The LDAR program is assumed to control the same percentage of emissions of non-VOM components, such as COS, H₂S, CO, CH₄, and CO₂, as VOM, or 97% for most all components, as VOM. However, the Permit does not require LDAR for these other pollutants. The LDAR monitoring requirements in Condition 4.9.6 only require monitoring for VOM. The other compounds can be reasonably expected to have different leak rates than VOM due to physical and chemical differences (*e.g.*, size of the molecule affects the amount that can escape through a given hole size). If there is no requirement to monitor these non-VOM components, there is no guarantee that the assumed control efficiency (93%-97%) will be achieved and thus no assurance that the source is minor for HAPs and is controlled by BACT. The Permit must be modified to require monitoring for all non-VOM components assumed to be controlled by LDAR.

3. Emission Limits Errors

The Application rejected the top controls as BACT based on the cost per ton of pollutant removed. The “uncontrolled tons of pollutant” is an important factor in this cost calculation and depends directly on uncontrolled emissions. Further, the Application claims that Taylorville is a minor source for HAPs as the emissions are less than 10 ton/yr for any individual HAP or 25 ton/yr total HAPs. Thus, the Permit must contain enforceable emission limits on pollutants involved in these determinations: VOCs, CO, COS, H₂S, CO₂e. Limits on these pollutants must be demonstrated through actual measurement. The Draft Permit contains some limits for equipment leaks but they are incomplete, contain errors, and are not enforceable.

First, the Draft Permit contains duplicative emission limits for fugitive components, in Conditions 4.9.2(d) and 4.9.5. The former should be eliminated.

Second, the emission limits in Draft Permit Condition 4.9.5 contains two errors that should be corrected. As drafted, it states: “Emissions of VOM, CO, CO₂e, COS, and methanol from affected component shall not exceed 2.44, 30.5, 177.4, and 1,255, 1.00 and 1.05 tons/year.” This condition should state: “Emissions of VOM, CO, CO₂, CO₂e, COS, and methanol from affected component shall not exceed 2.44, 30.5, 177.4, 1,255, 1.05, and 1.00 tons/year.”

4. Equipment Leak Emission Limits Are Not Enforceable

The Draft Permit does not require any monitoring to determine compliance with the emission limits. Rather, it stipulates estimation using “USEPA methodology” in Condition

⁴⁴⁶ Draft Permit, Cond. 4.9.2.a(i).

4.9.5. The methodology referenced in Condition 4.9.5 is not identified, *e.g.*, what emission factors would be used, what assumptions would be made about control effectiveness? How many components would be assumed and based on what? How would the emissions be speciated, *i.e.*, subdivided among the specific pollutants that are regulated?

No measurements are required to confirm that any of the inputs to this calculation are representative of Taylorville, *e.g.*, emission factors, control efficiencies, component counts. Nothing in the Draft Permit measures fugitive leaks in pounds per hour or tons per year or requires that they meet the estimates used to reject control options as BACT based on cost in dollars per ton. And nothing specifically addresses any component of these emissions except VOM, which is measured by EPA Method 21. This method does not detect the inorganic compounds in the fugitive emissions, such as CO, CO₂, COS, and H₂S. Thus, these limits are not enforceable.

The Draft Permit allows the Applicant to carry out the exact same calculation, using the same inputs and assumptions, as was used to estimate emissions in the Application. These emissions became the emission limits in the Permit Condition 4.9.5. Such an approach is a self-fulfilling prophecy that does nothing to ensure that the emission factors relied upon are accurate or that the assumed control efficiencies are actually being achieved. The U.S. EPA has held that such circular demonstrations are not enforceable limits on PTE. *See, e.g., In re Peabody Western Coal Co.*, 12 E.A.D. 22, CAA Appeal No. 04-01 (Feb. 18, 2005).

While the Draft Permit does require measuring the VOM concentration in ppm of individual leaks, it never requires converting them to emission rates in tons per year and adding them up to see if they exceed the estimates contained in the Application or the emission limit in Permit Condition 4.9.5. No measurements of any kind are required for other regulated pollutants.

Leaks identified under the proposed LDAR program are not taken into account in any way in the compliance demonstration. Even if testing showed higher fugitive emission rates or lower control efficiency; even if the final component count is higher than the assumed preliminary estimates; the Draft Permit bases compliance on the emission limits only on an undefined calculation that takes none of this into account.

As a result, there is no consequence to the Applicant if leaks occur more frequently than assumed in the emission calculations or more components are installed than assumed in the Application. It is impossible to violate any of the emission limits in Condition 4.9.5 regardless of how many leaks occur under the Draft Permit terms. The Draft Permit does not require that emissions from leaks above the levels assumed in the Application ever be quantified or tallied. If the number of leaks, concentration of pollutants in the leaks, or the size of the leaks exceeds the Application's assumptions, the Applicant is not even required to identify this problem, nor report it.

Thus, while the Applicant is required to carry out an LDAR program, the Applicant never has to use this program to determine whether the facility has more leaks or more components or poorer repair efficiency and thus more emissions than assumed to reject the top technologies as

BACT and to classify the facility as a minor source for HAPs. In sum, the emission limits in Condition 4.9.5 are unenforceable as a practical matter.

This is a major concern because the coal gasification industry is a new industry with no emission history. Further, recent evidence reviewed elsewhere in these comments indicates that potential emissions from equipment leaks may be underestimated by an order of magnitude. The permit emission limits should be based on actual measurements at existing coal gasification facilities, or confirmed through periodic direct testing at Taylorville after it is built using the bagging techniques described in the 1995 U.S. EPA report, *Protocol for Equipment Emission Estimates*⁴⁴⁷ or more advanced, state of the art remote sensing methods, reviewed elsewhere in these comments.

5. Averaging Time

The emission limits on fugitive leaks from equipment components is expressed in tons per year without any indicated averaging time.⁴⁴⁸ Reporting is only required on an annual basis.⁴⁴⁹ Limits without averaging times are not continuously enforceable. Further, there are no restrictions at all during the first year of operation, when upsets and malfunctions are most likely.

H. HAP EMISSIONS LIMITS ARE NOT ENFORCEABLE

Draft Permit Condition 3.4.b establishes facility-wide emission limits for lead and mercury at 0.22 and 0.10 ton/year, respectively. The Draft Permit requires analysis of the metals content a) in conjunction with emissions testing of the AGR unit and SRU; b) within 90 days of acceptance of a feedstock from a new source; c) within 90 days of a written request from IEPA; and d) at least once every two calendar years.⁴⁵⁰ The Draft Permit further requires that the Permittee keep a file containing the emission factors that the Permittee uses to calculate emissions of methanol, mercury, hydrogen chloride, hydrogen fluoride and other HAPs from the flare, the AGU, and the SRU with supporting documentation as well as records for total monthly and annual total HAP emissions from the flare, the AGU, and the SRU.⁴⁵¹ However, nowhere does the Draft Permit set out the formula for the emission respective calculations, or require that the Applicant demonstrate that monthly or annual total HAP emissions do not exceed the permit limits. Thus, the emission limits for HAPs are not enforceable.

Respectfully submitted,

Shannon Fisk, Ann Alexander
Senior Attorneys

⁴⁴⁷ U.S. EPA, *Protocol for Equipment Emission Estimates*, EPA-453/R-95-017 (Nov. 1995), available at <http://www.epa.gov/ttnchie1/efdocs/equipltks.pdf>, attached as Ex. 150.

⁴⁴⁸ Draft Permit, Cond. 4.9.5.

⁴⁴⁹ Draft Permit, Cond. 4.9.8.

⁴⁵⁰ Draft Permit, Cond. 4.1.9, p. 33.

⁴⁵¹ Draft Permit, Cond. 4.1-10-2.b.i and b.iv, p. 35, Cond. 4.1.10-3.a.i and a.iv, and Cond. 4.1.10-4.f.i and f.iv.

Natural Resources Defense Council
2 N. Riverside Plaza, Suite 2250
Chicago, IL 60660
Phone: (312) 651-7904
Fax: (312) 234-9633
sfisk@nrdc.org

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105
Phone: (415) 977-5716
Fax: (415) 977-5793
kristin.henry@sierraclub.org