BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

IN THE MATTER OF:)	APPEAL NUMBER: ______
CHRISTIAN COUNTY)	APPLICATION NUMBER: 05040027
GENERATION, LLC)	FACILITY ID NUMBER: 02106ACB

PETITION FOR REVIEW AND REQUEST FOR ORAL ARGUMENT

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INTRODUCTION

Pursuant to 42 U.S.C. 7607(b)(1) and 40 C.F.R. § 124.19(a), Natural Resources Defense Council ("NRDC") and Sierra Club (collectively, "Petitioners") petition for review of Prevention of Significant Deterioration ("PSD") approval set forth in the permit based on Application No. 05040027 (Facility Identification No. 02106ACB), which the Illinois Environmental Protection Agency ("IEPA") issued to Christian County Generation, LLC ("CCG" or "Applicant") on April 30, 2012. A copy of the PSD permit ("Permit") is attached as Ex. 1. The State of Illinois is authorized to administer the PSD permit program pursuant to a delegation of authority by the United States Environmental Protection Agency ("USEPA"). The Permit authorizes CCG to construct the Taylorville Energy Center, a coal-derived synthetic natural gas ("SNG") facility and an associated power block in Taylorville, Illinois ("TEC" or "Facility").

Petitioners contend that IEPA's best available control technology ("BACT") determination for the facility was clearly erroneous as a matter of law in violation of the Clean Air Act ("CAA"), and additionally raises important policy considerations that the Board should review, in four major respects. First, IEPA dismissed out of hand the feasibility of carbon capture and sequestration ("CCS") technology in Step 2 of its BACT determination based on general and unsubstantiated assertions of uncertainty, without any genuine attempt at site-specific feasibility analysis, and without regard to extensive site-specific analysis previously performed by the applicant concluding that CCS is feasible. In so doing, IEPA failed to follow BACT's case-by-case statutory requirements, as well as USEPA guidance requiring a full site-specific inquiry into the feasibility of CCS for large-scale projects like TEC. Second, IEPA dismissed cleaner low-sulfur western coal as a basis for BACT based on an Illinois statute affording a subsidy for facilities using Illinois coal, thereby unlawfully circumventing federal

BACT requirements concerning consideration of clean fuels based on state law, in contravention of the Supremacy Clause. Third, IEPA rejected available and feasible controls for leaking components currently in widespread use – leakless component technology and leak detection and repair ("LDAR") programs – based on arbitrary and deficient cost effectiveness analysis. Fourth, IEPA's modeling analysis was fundamentally arbitrary and capricious because IEPA failed to conduct ozone modeling and, instead, relied on the Scheffe Tables to estimate ozone emissions even though EPA has denounced that method.

Petitioners request oral argument in the above-captioned matter. Oral argument would assist the Board in its deliberations on the issues presented by the case because the issues raised herein are issues of first impression for the Board and the USEPA, are a source of significant public interest, and/or are of a nature such that oral argument would materially assist in their resolution.

THRESHOLD PROCEDURAL REQUIREMENTS

Petitioners satisfy the threshold requirements for filing a petition for review under 40 C.F.R. Part 124. Petitioners have standing to petition for review of the permit decision because they participated in the public comment period on the draft permit. 40 C.F.R. § 124.19(a). *See* comments filed by Petitioners NRDC and Sierra Club ("Petitioners' Comments"), attached as Ex. 2.[1] The issues raised by Petitioners below were raised with IEPA during the public comment period. Consequently, the Board has jurisdiction to hear Petitioners' timely request for review.

[1] The exhibits to Petitioners' Comments, which exceed 1.6 gigabytes in size, are being submitted in electronic form only.

ISSUES PRESENTED FOR REVIEW

Petitioners respectfully request Board review of the following issues:

1. Whether IEPA's rejection of CCS at Step 2 of its top-down BACT analysis without site-specific inquiry constitutes a clearly erroneous conclusion of law or an important policy consideration that the Board should review and reverse;

2. Whether IEPA's rejection of cleaner low-sulfur coal as the basis for BACT based on a state law subsidy offered to Illinois Basin coal constitutes a clearly erroneous conclusion of law or an important policy consideration that the Board should review and reverse.

3. Whether IEPA's use of altered categorical emission factors from another source type to estimate the facility's potential to emit from component leaks, and its ensuing rejection of technology to control those leaks in Step 4 of its top-down BACT analysis, constitute a clearly erroneous conclusion of law or an important policy consideration that the Board should review and reverse;

4. Whether IEPA's failure to require the applicant to model ozone air quality impacts constitutes a clearly erroneous conclusion of law or an important policy consideration that the Board should review and reverse.

5. Whether IEPA's failure to inform CCG that under its current permit it cannot build TEC in phases, in which the natural gas combined-cycle plant during is initially built and the gasifier block is built years later, constitutes a clearly erroneous conclusion of law or an important consideration that the Board should review and reverse.

STATEMENT OF FACTS

CCG submitted the Application for a permit to construct the Facility in several parts, the last submitted October 27, 2010 (the "Application"). *See* Project Summary, Petitioners'

Comments Ex. 90, at 3 n. 1. The Application was for a facility with a nominal capacity to produce 64 million cubic feet of SNG per day, which could then be either sold as a product leaving the plant by pipeline, or be used at an on-site power block to generate electricity. *Id.* at 3. CCG had applied for and received a permit in January, 2008 from IEPA for a different type of facility at the site, an integrated gasification combined cycle ("IGCC") plant for generating power without the capability of selling SNG to the market. CCG had also submitted an earlier application for a version of the Project in April 2008, which was updated by the 2010 Application. *Id.* at 3 n. 1.

The 2010 Application was submitted with the stated aim of qualifying for various subsidies and benefits proposed in the Illinois General Assembly for supposed "clean coal" facilities. In each case, the proposed legislation offered the subsidies and benefits to a Facility that, *inter alia*, employs CCS to curb its CO_2 emissions. *Id.* at 6, 22. *citing* Illinois' Clean Coal Portfolio Standard Law (20 ILCS 3855/1-75, as amended by P.A. 95-1027, effective June 1, 2009) ("Clean Coal Act"). CCS is a process that captures CO_2 before it is emitted to the atmosphere and transfers it via pipeline to a site where it can be injected for permanent underground sequestration. During the pendency of the Application, additional legislation was introduced in the Illinois General Assembly creating further subsidies and incentives for "clean coal" facilities, similarly requiring use of Illinois Basin coal and CCS. This legislation would provide CCG with construction subsidies and guaranteed purchases of its SNG if it met those criteria.[2]

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[2] *See also* Amendment to Senate Bill 678 filed in the Illinois General Assembly May 23, 2012, *available at* http://www.ilga.gov/legislation/97/SB/PDF/09700SB0678ham002.pdf. This legislation proposes yet a different configuration for the Facility, which would not include the SNG facility but only the gas-fired power block.

In connection with the Clean Coal Act, the Applicant submitted extensive information to the Illinois General Assembly purporting to demonstrate the feasibility of CCS. These included, *inter alia*, a Facility Cost Report (Petitioners' Comments Ex. 52), which incorporated in turn twin reports developed by Schlumberger Carbon Services ("Schlumberger") – a Feasibility Study (*Id.* Ex. 53) and a Cost Study (*Id.* Ex. 54) **–** evaluating in significant detail the possibility of sequestration of captured CO_2 at the nearby Mt. Simon sandstone formation in Illinois. *See* Petitioners' Comments at 60. Additionally, in September, 2011, CCG applied to USEPA for a Class VI underground injection permit for CCS at the nearby Mt. Simon sandstone formation in connection with the Facility. Petitioners' Comments Ex. 58. That application remains pending. Petitioners' Comments at 63.

IEPA issued the draft Permit on October 17, 2011. On January 3, 2012, Petitioners submitted their Comments to IEPA (Ex. 1). Petitioners' Comments covered multiple technical and legal issues, including both the issues raised on this appeal, as well as additional issues that Petitioners have decided not to appeal. The final Permit was issued April 30, 2012, together with a Responsiveness Summary ("RS") (attached as Ex. 3). Petitioners were served with a copy of the Permit and RS via electronic mail on May 1, 2012. IEPA made no changes to the Permit concerning any of the issues raised in this appeal.

ARGUMENT

I. IEPA Erred In its BACT Determination for CO_2 Emissions from the AGR Vent

The acid gas removal ("AGR") step of the Facility's gasification process is an enormous source of CO_2. This step, which is part of a set of processes to remove contaminants in the gasification process, generates the vast majority of the Facility's CO_2 and overall greenhouse gas emissions. The Permit allows CO_2 from the AGR process to be vented uncontrolled to the atmosphere, resulting in emissions of 2,510,321 tons per year ("tpy") according to the Project Summary. Petitioners' Comments at 55-6.

IEPA failed to in its duty to evaluate CCS as part of its BACT analysis for the AGR vent, in particular regarding the technical feasibility of the transportation and underground storage components of CCS. IEPA had before it the Applicant's overwhelmingly detailed technical explanation of why CCS is technically feasible – as well as cost effective[3] – at the Facility, submitted in a legislative context where demonstrating feasibility was to CCG's financial advantage. Yet when the Applicant attempted to walk back and disregard its own analysis in support of a claim that CCS is not feasible for BACT purposes, IEPA accepted the Applicant's turnabout position on the matter without any detailed technical review of either the Applicant's prior documentation (including the Schlumberger Feasibility Study and Cost Study), or of the site-specific characteristics that would bear on the feasibility of CCS for BACT purposes.

As discussed below, IEPA essentially justifies in the RS its rejection of CCS as BACT by raising a series of questions as to whether CCS overall as a technology – rather than specifically at the Facility – is too fraught with uncertainty to be feasible. In so doing, it argues as well that use of CCS at another coal gasification plant and at other types of sources – including a

[3] Petitioners presented extensive information, based predominantly on TEC's own analysis, demonstrating that CCS should be cost-effective at Mt. Simon, had IEPA reached Step 4 of BACT analysis where such considerations are appropriate. *See* Petitioners' Comments at 68 *et seq.* Since IEPA expressly declined to reach Step 4, we are not raising the Step 4 cost effectiveness issues in this appeal (*see* RS at 138). Nonetheless, since IEPA responded to Petitioners' conclusions regarding cost effectiveness, RS at 138-146, it bears noting that the response was badly in error. Petitioners calculated, based on the Cost Report, that the annualized cost of implementing CCS would be $4.58 per ton. Petitioners' Comments at 71 and Ex. 137. Similarly, IEPA argues that Petitioners erred by using an undocumented power price of $50/MWh as opposed to their forecasted power price over the life of TEC. *See* RS at 140. Once again, this argument is inconsistent with the overnight cost method that must be used in a cost effectiveness analysis. Proper BACT analysis does not use forecasted power price over the life of the facility, but rather the cost of replacement power at the time of the estimate. The value used by Petitioners, $50/MWh, is at the upper end of the range, and is a common default in similar analyses. Finally, the revised costs that IEPA erroneously calculates -- $31.49 per ton or $17.52 per ton, depending on specified variables – are on the low end of $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). *See* Petitioners' Comments at 72.

sequestration projected at Mt. Simon being implemented by Archer Daniels Midland ("ADM") in connection with an ethanol manufacturing facility – do not sufficiently demonstrate the feasibility of CCS for the TEC Facility. However, IEPA does not offer any site-specific information or analysis of its own to contravene the Applicant's voluminous documentation of the feasibility of CCS for the Facility and Mt. Simon, or any specific basis for distinguishing other CCS projects from TEC so as to justify rejection of CCS here. In sum, instead of attempting to answer the general questions surrounding CCS by assessing site-specific information as the law requires it to do, IEPA rests on the questions themselves.

This punt is inconsistent with the basic statutory requirements of BACT analysis and the specific guidance and positions taken by USEPA on assessment of CCS's technical feasibility. BACT analysis requires – and specifically includes in Step 2 of top-down analysis – a *case-by-case* determination of the feasibility of an available technology – *i.e.*, a site-specific analysis as to whether the technology can be implemented as a technical matter at a proposed project. Moreover, USEPA has clearly set forth, in both its GHG BACT guidance and more recently in its draft GHG New Source Performance Standards ("NSPS"), that CCS is an available technology that will in at least some cases be feasible for, *inter alia*, coal gasification facilities. Nor can IEPA rest on supposed general uncertainties while making little to no effort to resolve them for TEC, as the applicant has a legal duty to provide all information necessary for ensuring that BACT is applied.

Accordingly, for the reasons discussed below, the Board should remand the Permit to require IEPA to review the feasibility of CCS as BACT for the facility on a case-by-case, site-specific basis, fully assessing the feasibility of carbon capture, transportation, and storage.

A. A BACT Determination, for CCS or Otherwise, Requires Case-By-Case Feasibility Analysis

A full explication of the legal requirements of the BACT process is set forth in Petitioners' Comments at 41 *et seq.*, and incorporated by reference. As discussed therein, BACT is typically evaluated through a 5-step top-down process described in the NSR Manual.[4] 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 Envtl. Conserv.*, 298 F.3d 814, 822 (9th Cir. 2002). The five top-down steps are (1) identify all available control options, (2) eliminate technically infeasible options, (3) rank remaining control technologies by control effectiveness, (4) evaluate the most effective controls and document the results, and (5) select BACT. To aid this process, the applicant is required to submit "*all* information necessary to perform any analysis or make any determination required under this section." 40 C.F.R. § 52.21(n) (emphases added). IEPA has adopted this top-down process.

1. General BACT Principles Require Case-by-Case Feasibility Analysis to Determine Applicability of an Available Technology

At the heart of a BACT determination is the explicit Clean Air Act ("CAA") requirement that the determination be made on a case-by-case basis. The CAA provides that BACT must be established "on a *case-by-case basis*, taking into account energy, environmental, and economic impacts and other costs, determines is *achievable for such source* or modification through 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." 40 C.F.R. § 52.21(b)(12) (emphasis added). The NSR Manual further describes how BACT Step 2

[4] U.S. Environmental Protection Agency, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990. *See* Petitioners' Comments at 15 n. 45.

– the step at which IEPA eliminated CCS as infeasible – specifically calls for case-specific technical analysis, stating that "[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 specific objective of the case-by-case evaluation in Step 2 is to determine, in a two-part analysis, whether the 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 deployed or "soon to be deployed" at a similar source type. However, even if it is not deployed at a similar source, and thus the presumption does not apply, the permitting authority must still make its own reasoned technical judgment as to applicability where the technology has been deployed at other source types:

> 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 this instance, IEPA identified one other coal gasification plant, Dakota Gasification's Great Plains Synfuels Plant, that is deploying CCS (as well as four others at which it is proposed for use). RS at 115. The presumption of feasibility of CCS at TEC therefore applied. Additionally, Petitioners identified the CCS project being deployed by ADM at different source type (an ethanol plant) at Mt. Simon, such that even if the presumption of applicability based on Dakota Gasification could be overcome, IEPA was still required to make a reasoned technical judgment as to applicability of CCS 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."

2. An Applicant Must Provide Detailed Case-by-Case BACT Feasibility Analysis for CCS Except in Limited Circumstances that are Inapplicable Here

In its PSD and Permitting Guidance for Greenhouse Gases ("USEPA GHG BACT Guidance" or "Guidance") (Petitioners' Comments Ex. 51) issued last year, USEPA describes the applicability of BACT determination principles specifically in the context of controlling CO_2 and other GHGs.[5] The Guidance specifically finds that although CCS is "not in widespread use at this time," it is nonetheless an "available" technology for purposes of BACT Step 1 for facilities such as TEC "emitting CO_2 in large amounts and industrial facilities with high-purity CO_2 streams." Guidance at 32, 35.

[5] Petitioners here cite the GHG BACT Guidance solely for its discussion of the detailed case-by-case analysis as applied to CCS, noting disagreement with EPA that the factors listed are all properly considered technical feasibility questions, *see* Petitioners' Comments at 58 ("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."). In addition, Petitioners submitted comments to EPA on the GHG BACT Guidance, available at regulations.gov, Doc. No. EPA-HQ-OAR-2010-0841-0090.

The Guidance reaffirms that the stringent case-by-case requirements of BACT Step 2 are applicable to determinations of whether CCS constitutes BACT, with certain limited circumstances allowing for a less detailed record that does not apply to the TEC permit. As an overall matter, the Guidance makes clear that a determination in Step 2 that CCS does *not* constitute BACT requires an affirmative detailed technical demonstration by the permitting agency of the reasons supporting the conclusion of infeasibility, along the lines more generally described in the NSR manual. Specifically, the Guidance provides:

> CCS is composed of three main components: CO2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 *if it can be shown* that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together *are deemed technically infeasible for the proposed source*, taking into account the integration of the CCS components with the base facility and site-specific considerations (*e.g.*, space for CO2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).

Guidance at 35-36. Thus, the Guidance reiterates the general requirement in the Manual of case-by-case reasoned technical judgment to determine applicability, regardless of whether CCS has been applied at the same source type. Where it has not been applied at the same source type, the Guidance, like the Manual, calls for Step 2 applicability to be determined based on a detailed technical comparison of the feasibility of the three core components of CCS (capture, transport, storage) at the disparate source types.

The Guidance presumes overall that CCS will be feasible in some instances if not others, stating, "While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option *in certain cases*." *Id.* at 36 (emphasis added).

The Guidance further recognizes that there are some types of smaller facilities, with limited GHG emissions, for which a large-scale CCS project will plainly be infeasible, and hence that such facilities should not be required to present detailed technical information evaluating something that they clearly will never be able to do. It therefore makes specific allowance for a more limited Step 2 analysis for such facilities. However, it is clear that this limited relaxation of the Step 2 requirement for detailed analysis does not apply to the TEC Facility – a large-scale industrial project located very near a geologic formation already identified as suitable for CCS, and for which voluminous documentation of technical feasibility already exists.

Specifically, the Guidance provides as follows:

> The level of detail supporting the justification for the removal of CCS in Step 2 will vary depending on the nature of the source under review and the opportunities for CO2 transport and storage. . . . 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. However, in cases where it is clear that 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. In addition, a permitting authority may make a determination to dismiss CCS *for a small natural gas-fired package boiler*, *for example*, on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured CO2 given the nature of the project.
>
> ***
>
> Logistical hurdles for 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. *Not every source has the resources* to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and *smaller sources* will likely be more constrained in this regard.

Guidance at 36 (emphasis added).

The limited exception allowing less thoroughgoing site-specific technical review in Step 2 is plainly envisioned only for sources for which there are facially obvious hurdles to feasibility: either where the sources are very small ("smaller sources," *e.g.*, a "small natural gas-fired package boiler," a source with limited "resources," or a source that "emits CO2 in amounts just over the relevant GHG threshold"), or otherwise face obvious inherent barriers to CCS (*e.g.*, because they "produce a low purity CO2 stream"). These exempted sources, however, are contrasted with the types of sources for which full site-specific Step 2 analysis for CCS is still required, which specifically include those for which "sequestration opportunities already exist in the area where the source is." The Facility – a large industrial-scale emitter of CO_2 located a mere 30 miles from documented and excellent sequestration site (the Mt. Simon formation) already being put to use for CCS by another facility (ADM), producing a pure stream of CO_2 (*see* Petitioners' Comments at 67 n. 212) –falls into the non-exempt category, requiring full technical analysis of Step 2 feasibility.

B. IEPA Failed to Conduct Site-Specific, Case-by-Case Step 2 Feasibility Analysis for CCS as BACT for TEC's CO_2 Emissions

IEPA failed in its permit determination to meet the basic analytical requirements of BACT Step 2 technical feasibility analysis, as further enumerated for CCS in the USEPA GHG BACT Guidance. IEPA cited in general terms numerous technical and logistical questions that CCG would need to answer before implementing CCS at the Facility. But rather than actually evaluating whether these questions can feasibly be answered, IEPA relied on the mere existence of these questions to sweepingly dismiss CCS as infeasible. This approach is clearly erroneous under CAA BACT requirements and the Guidance.

Instead of the generic dismissal of CCS proffered by IEPA, the Agency was required to conduct BACT feasibility analysis in Step 2 consistent with the two-part consideration of "availability" and "applicability" described in the Manual – with its attendant presumption of feasibility flowing from CCS deployment at Dakota gasification, and case-by-case applicability comparison requirement flowing from its deployment at ADM. IEPA further erred in improperly mixing non-technical concerns into its purported technical feasibility analysis (many of those concerns being, in any event, no longer extant). Finally, to the extent IEPA had legitimate concerns regarding unavoidable future uncertainties that attend CCS projects, it erred in not identifying options for addressing any such uncertainties rather than simply dismissing CCS out of hand – in particular the option of an adjustable BACT permit, and fulfilling its legal obligation to require a full information concerning available BACT alternatives.

1. IEPA Improperly Dismissed Site-Specific Evidence of CCS Feasibility Based on Broad Generic Issues Common to CCS Projects

Although the BACT determination principles described in subsection I.A clearly call for addressing Step 2 through a close technical comparison of the TEC Facility to other sources (similar and dissimilar) that have deployed CCS, IEPA takes a very different approach to Step 2. Its analysis of the feasibility of CCS at the site consists almost entirely of efforts to use general questions regarding CCS to explain away abundant evidence in the record – much of it generated by the Applicant – that CCS is indeed feasible for the Facility. As discussed below, this approach not only lands far from the case-by-case analytical requirements for a BACT feasibility determination, but also sets up an impossibly high standard for CCS that runs directly counter to the objectives of the Guidance.

Tenaska prepared and submitted to the Illinois General Assembly extensive documentation of the feasibility (as well as cost-effectiveness) of sequestering the CO_2 from the

AGR vent at Illinois' Mt. Simon sandstone formation, approximately 30 miles away. These thoroughgoing analyses by the Applicant overwhelmingly support the feasibility of CCS at Mt. Simon. The Schlumberger Feasibility Study concluded, "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 CO_2 produced by the plant over a planned operational life of 30 years." Petitioners' Comments at 60, citing Ex. 54. The Cost Study (which evaluated a mix of technical feasibility and cost issues) similarly concluded,

> 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 CO_2 resulting *in reduced right of way*. Also, the target area is under and adjacent to the *plant resulting in minimal pipeline cost*.

Petitioners' Comments at 61, citing Ex. 53 (emphasis added).

Additionally, CCG submitted a Class VI underground injection permit application to USEPA which likewise documented the feasibility of CCS at Mt. Simon. The 2D geologic survey of Mt. Simon as reported in that application was likewise 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 CO_2 storage;

3) Preliminary results of the MGSC project in Decatur suggest *sufficient reservoir potential is present* with porosity and permeability.

Petitioners' Comments at 63, citing Ex. 58 (Class VI permit application) (emphasis added). The application also includes a long-term monitoring plan. *Id.*

Finally, CCG submitted an application to the U.S. Department of Energy ("USDOE") for a $3.2 billion loan guarantee available to projects that capture and sequester carbon. In the application, it described an intention to sequester using EOR, but noted that Mt. Simon was a good alternative as well (in part because the ADM project is already in progress):

> As mentioned above, the Applicant does not plan to rely exclusively upon its ability to contract with a third party to take delivery of C02 for sequestration through enhanced oil recovery. The plant is located at a promising site for geologic sequestration that is 50 miles to the west of the Mattoon, Illinois site that was selected as the preferred FutureGen location in pmi based upon the favorable geology for sequestration. It also is less than 30 miles to the south and west of the site of the Decatur, Illinois DOE sequestration demonstration project at which l00,000 tons per year (for three years) and a cumulative one million tons of C02 produced by Archer Daniels Midland is to be sequestered. This early sequestration work nearby is valuable to the Project effort because it establishes permitting procedures under existing law and regulations for the safe injection of C02 into geologic formations with the capacity to receive large volumes of C02. This part of Illinois sits above the Mount Simon formation.

DOE loan application, attached as Ex. 4, at 13.[6] IEPA's Project Summary prepared in connection with the draft Permit (Petitioners' Comments Ex. 90) devotes all of one paragraph to flagging and dismissing the Mt. Simon sequestration option. *See* Petitioners' Comments Ex. 94 (Project Summary) at 32. That paragraph reads in its entirety:

> A second approach to sequestration of CO_2 from the CO_2 vent on the AGR Unit would be geologic sequestration in sandstone in the Mt. Simon formation, which is present deep underground in the region in which the plant is located. A detailed feasibility study of this sequestration option for the plant was performed by Schlumberger Carbon Services in February 2010 to evaluate: 1) whether the proposed site has capacity to sequester the expected volume of CO_2 from the

[6] Relevant excerpts only from the 1,500+ page application are included in the paper copy of the exhibits. Both the full application (Ex. 4) and the relevant excerpt (Ex. 4a) are included in the electronic copy.

> plant, 2) containment of the sequestration reservoir, and 3) infrastructure requirements for sequestration (number and dimensions of injection wells, operational strategies, etc.) Although the results of this preliminary study were favorable, many other technical issues associated with geologic CO2 sequestration still need to resolved [sic]. In addition, there are unresolved issues involving the regulatory requirements for sequestration and liability associated with sequestration. Further development of sequestration is needed before a BACT emission limit could be set for the proposed plant that is predicated upon implementation of CCS.

Ex. 94 at 32.

Additionally, in connection with the more general question of the feasibility of CCS as a CO_2 control measure, IEPA references "[t]hree full-scale IGCC projects (Summit Texas Clean Energy, Southern Company Kemper County, and Hydrogen Energy California). . . recently proposed to commercially demonstrate the use of CCS under the United States Department of Energy's (USDOE) Clean Coal Power Initiative (CCPI)." *Id.* at 30. It dismisses these projects (and impliedly CCS generally) without further discussion for the following three listed reasons, based on a 2010 federal report:

- The existence of market failures, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions.
- The need for a legal/regulatory framework for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO2 can be stored safely and securely.
- Clarity with respect to the long-term liability for CO2 sequestration, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.
- 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. As discussed in detail below, *see infra* subsection I.B.3, these policy concerns are inappropriate considerations for the technical determination of feasibility required in BACT Step 2.

The Project Summary contains little discussion of CCS projects other than these, and no mention of the ADM sequestration project at nearby Mt. Simon. It further dismisses the Dakota Gasification project's CCS on the grounds that enhanced oil recovery ("EOR") is readily available at that site, but makes no attempt to evaluate or quantify the comparable suitability of the Mt. Simon site for sequestration.[7] Project Summary at 31. The Summary also makes no reference to CCG's Class VI permit application, and the extensive information it contains concerning CCG's verification of the feasibility of sequestration at Mt. Simon.

In the RS, responding to Petitioners' extensive presentation in their Comments regarding CCG's Cost and Feasibility Studies and Class VI permit as well as the ADM project (Petitioners' Comments at 55 *et seq*.), IEPA reiterates its sweeping generalizations regarding the purported uncertainty surrounding CCS. The RS references a mix of the generic "hurdles" to CCS implementation that are mentioned in the Project Summary and expressly addressed in the USEPA GHG BACT guidance:

> As the Project Summary discusses, considerable uncertainty exists with respect to a number of requisite conditions for CCS here, including access to an existing pipeline and a suitable geologic reservoir over the life of the plant, sequestration field land and subsurface rights acquisition, development of a site for secure long-term storage, proven geology favorable for long-term storage, and other uncertainties about the long-term ability of the Mt. Simon formation to sequester CO2. *See* Project Summary at 29-32.

RS at 114.

The RS places heavy emphasis on two particular aspects of these purported obstacles as demonstrating the overall infeasibility of CCS: that the feasibility concerns it cites are "largely outside of CCG's ownership and control," and that there can be no "certainty" at the permitting

[7] Petitioners also raised claims in their comments concerning specifically IEPA's failure to adequately evaluate the possible use of captured CO_2 from the TEC facility in EOR processes. *See* Petitioners' Comments at 64 *et seq.* While Petitioners do not believe that IEPA's analysis of EOR met the required standard for BACT Step 2 feasibility analysis, they have chosen not to appeal IEPA's findings with regard to the feasibility of EOR at this time. This appeal concerns the feasibility of CCS at the Mt. Simon sandstone formation discussed herein.

stage as to whether and how the cited obstacles can be overcome. *Id.* It states that, although the Schlumberger studies indicated "favorable geologic conditions for CO_2 sequestration using the Mt. Simon formation" for the plant's anticipated lifetime, this finding "does not constitute a guarantee that CO_2 injection will be available initially at startup or consistently over the life of the plant." *Id.* at 120. It further avers that "[a]lthough the formation looks promising in its CO_2 retention capacity, given the current status of CO_2 sequestration technology, the formation's ability to adequately hold the volume of CO_2 produced by the TEC and to accommodate injection at the rate needed for the TEC is theoretical until demonstrated in practice, following actual well installation and injection of CO_2 over an extended period of time." *Id.* IEPA also asserts that since the Schlumberger geological modeling is not based on core sampling for the specific site being considered, "it cannot be relied upon as a conclusive evaluation" of the particular site being considered. *Id.*

The RS dismisses the significance of the Class VI permit application addressed in Petitioners' comments on the grounds that IEPA cannot "guarantee the success" of CCG's efforts to obtain a permit, and that the permitting process laid out by USEPA for CCS is "a lengthy, iterative process where several tests must be performed before operation of the well may be authorized, including formation testing, logging, sampling, and testing of the well and surrounding formations, and mechanical integrity tests." *Id.* at 122-23. It similarly dismisses the significance of the ongoing ADM project at Mt. Simon on the ground that "it is possible" that the CCG project could be impacted by interruptions and changes that would not be an issue for ADM's voluntary project. *Id.* at 121.

The deficiencies of this analysis are manifold, and detailed further in the sections below. But they all essentially boil down to one major error: IEPA rejects CCS not because of any finding that it is not available or applicable for CCG's proposed site, but because of issues that arise in evaluating proposed CCS projects in general. This approach is wholly contrary to BACT statutory requirements. USEPA's Guidance document expressly recognizes the potential obstacles to CCS implementation, but concludes that they must be considered and addressed on a case-by-case basis as in any other BACT determination. Indeed, the grounds on which IEPA rejects CCS as infeasible based on uncertainty – pipeline construction issues, subsurface rights acquisition, and access to a suitable geologic reservoir for sequestration (RS at 113-14) – reiterate almost word-for-word the factors listed in the USEPA GHG BACT Guidance as being the *subjects* of required site-specific inquiry in most cases, not the answers in and of themselves (Guidance at 36). The Guidance specifically states, "CCS may be eliminated from a BACT analysis in Step 2 if the three components working together *are deemed technically infeasible for the proposed source*, taking into account the integration of the CCS components *with the base facility and site-specific considerations* (*e.g.*, space for CO2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options)." *Id.* at 35-6. Moreover, the Guidance makes clear that such careful, case-by-case technical analysis is particularly important and appropriate for large industrial scale projects such as TEC (as opposed to, *e.g.*, a "small natural gas-fired package boiler"). *See supra* Section I.A.2.

In addition to the USEPA GHG BACT Guidance, USEPA's proposed NSPS CO_2 rule issued in April 2012 further evidences USEPA's overall position that CCS is feasible as a general matter for new coal gasification sources, contrary to IEPA's implicit position that generic concerns render CCS *per se* infeasible. Although the GHG BACT rule contains a potential grandfathering carve-out for the TEC Facility (dependent upon its construction schedule, and unrelated to BACT obligations) (72 Fed.Reg. 22,392, 22,422 (April 30, 2007)), the draft rule is grounded in an overall determination that coal gasification units "should also be able to meet this [proposed NSPS] standard by employing carbon capture and storage (CCS) technology." *Id.* at 22,394. USEPA's pronouncements on the matter are not run-of-the-mill technical guidance, but rather a technical determination supporting the Agency's rulemaking, in turn a core part of its regulatory program for GHGs.

If, as IEPA suggests, 30+ years of absolute certainty is what is required at the permitting stage in order for CCS to be identified as feasible in BACT Step 2, then CCS will essentially *never* be feasible. Indeed, CCS will not be feasible even if an Applicant must merely "guarantee the success" of its Class VI permit application to USEPA at the construction permitting stage, as IEPA also suggests. As IEPA acknowledges in the RS, USEPA's Class VI permitting process is long and iterative. Yet it presents no actual reason to believe that CCG's Class VI permit application will not eventually be granted (indeed, based on the Applicant's data, there is every reason to believe it will). Petitioners' Comments at 63. IEPA's concern appears to be grounded solely in the lengthy and iterative – and therefore inherently uncertain at this stage – structure of the Class VI permit process itself. Of course, even after USEPA does issue a permit, a CCS project still would not meet the threshold standard set by IEPA in this matter, which is that there be a "*guarantee* that CO_2 injection will be available . . . consistently over the life of the plant." *Id.* at 120 (emphasis added). Simply put, this standard is antithetical to BACT.

Similarly, the fact that some aspects of a CCS project are outside the immediate control of the permit applicant is common to CCS projects in general. In virtually every case requiring a pipeline, rights-of-way will need to be acquired. One can conceive of situations in which the geographic position of a facility – *e.g.*, bordered on all sides by a nature preserve – might make it logistically impossible for the facility to obtain such rights of way. But no claim of that nature was ever made in the voluminous documentation that CCG submitted to the General Assembly touting the feasibility and practicability of CCS at Mt. Simon. Similarly, while acquisition of subsurface rights may at times be an issue for CCS implementation – for example, where possible sequestration sites are slated for other development uses – no claim of that sort has been made by CCG anywhere in the record. The fact that third-party actions may be required in order to render CCS feasible at a particular project site does not logically lead to the conclusion that such actions are necessarily unobtainable.

At bottom, confronted with overwhelming evidence generated by the Applicant itself that CCS is feasible for the TEC Facility, all IEPA can find to say is that the information is not perfect and absolute. Simply pointing out "you missed a spot" does not constitute the careful site-specific technical analysis required by the CAA or contemplated by USEPA's GHG BACT Guidance. The documentation provided by the Applicant to the Illinois General Assembly demonstrates that the Mt. Simon formation, and the proposed Facility's proximity to it, is a virtually ideal setup for implementation of CCS. If the feasibility of CCS can be dismissed here, based on vague and non-site specific concerns, then it can be dismissed anywhere for the same reasons. That is plainly not USEPA's interpretation of what BACT requires for CCS, consistent with the statute and decades of BACT determinations reviewed by this board.

2. IEPA Erroneously Failed to Assess the Technical Feasibility of CCS by Assessing both Availability and Applicability of the Technology

IEPA's approach to BACT Step 2 described above represents an erroneous failure to determine, as outlined in the Manual and the USEPA GHG BACT Guidance, whether the implementation of CCS at other sources supports the applicability of CCS at the TEC Facility. As discussed in Section I.A.1 *supra*, the permitting authority is required presume the applicability of a control technology if it has been (or is about to be) deployed at the same or similar source type. PSD Manual at B-17. To the extent it has not been deployed at a similar source type, the permitting authority is required to exercise "reasoned technical judgment" to determine applicability.

Since IEPA had before it evidence both that at least one gasification facility – the Dakota Gasification Great Plains -- is employing CCS (RS at 115), it was required to presume the applicability of CCS to the TEC Facility. As discussed in subsection I.B.1 *supra*, IEPA's cursory reference to the purported absence of EOR opportunities near the proposed Facility does not overcome the presumption, as it has no bearing on the question whether the Mt. Simon formation would be an equally feasible CO_2 sequestration site.

Additionally, since, IEPA also had before it extensive information concerning the use of CCS by ADM at Illinois' nearby Mt. Simon sandstone formation in connection with a different source type, even if the presumption based on Dakota Gasification were overcome (and it should not be), IEPA was nonetheless required in Step 2 to conduct a technical evaluation of each of the three CCS components identified in the Guidance – CO_2 capture and/or compression, transport, and storage – and make a determination as to whether there are "significant differences" with respect to each of these components between TEC and the sources that have implemented CCS, taking into account "temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled." IEPA should not have pronounced CCS infeasible at the TEC site until and unless "the three components working together are deemed technically infeasible for the proposed source," taking into account site-specific factors including "the integration of the CCS components with the base facility and site-specific considerations (*e.g.*, space for CO2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options)." Guidance at 35-36. IEPA conducted none of this site-specific analysis in its cursory rejection of CCS, which dismissed ADM's CCS project from consideration solely because it does not confer certainty that TEC's would be equally functional. Its BACT analysis was therefore deficient as a matter of law.

3. IEPA Erroneously Relied on Non-Technical Considerations in Rejecting CCS as BACT

Step 2 is expressly a "technical" feasibility determination, based on based on "physical, chemical, and engineering principles." NSR Manual at B-6. However, a significant number of the purported hurdles to implementation of CCS cited by IEPA are non-technical in nature, and hence inappropriate for consideration in BACT analysis. *See generally Massachusetts v. EPA*, 549 U.S. 497, 532-534 (CAA statutory text requires the agency to conduct a scientific analysis of endangerment; it may not provide a "laundry list of reasons not to regulate" as a basis for "declining to form a scientific judgment"). Specifically, IEPA cites (i) "The existence of market failures, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions"; (ii) "The need for a legal/regulatory framework for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO2 can be stored safely and securely"; (iii) "Clarity with respect to the long-term liability for CO2 sequestration," and (iv) "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." Project Summary at 30. Clearly, the need to "foster public understanding" and "build trust" concerning CCS, while perhaps valid concerns in general, are not technical factors appropriate to Step 2 feasibility analysis.

In any event, the source that IEPA cites for these concerns, an August 2010 report by the federal Interagency Task Force for Carbon Capture and Storage, pre-dates the federal UIC program for Class VI CCS permits, which addressed a host of those issues. USEPA promulgated its Class VI rule for underground injection of CO_2 for geologic sequestration in December 2010. 40 CFR 146. The Class VI rule provides a well-defined regulatory path for a facility developer wishing to obtain a permit for CO_2 sequestration, and addresses the specific concerns identified by IEPA in the Project Summary. Specifically, as the Project Summary itself correctly describes it (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 CO_2 when it[i]s sequestered, including the large volume of material, the buoyancy and viscosity of CO_2, and its chemical properties, as compared 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."

IEPA fails to acknowledge in the RS the extent to which the UIC program has resolved its initial concerns. Its only response is that, while the UIC program is now in place, there are still some guidance documents regarding monitoring and the like that have not yet been issued. RS at 122.

IEPA's failure to address the significance of the federal UIC program in addressing the purported logistical concerns with CCS throws into sharp relief the inordinate degree to which IEPA relied on the Applicant's analysis (in the application, that is, not the Schlumberger studies) concerning the purported infeasibility of CCS. The October 2010 Application grounds this identical set of concerns in the *absence* at that time of a federal regulatory program for permitting CCS underground injection. Petitioners' Comments at 63. While IEPA correctly notes in its Project Summary that the federal UIC regulations were issued two months after submittal of the Application, it nonetheless adopts wholesale the Applicant's conclusions that flowed from the then-absence of a regulatory program.

4. IEPA Erroneously Failed to Consider Appropriate and Available Courses of Action for Addressing any Inherent Uncertainties in CCS Implementation

To the extent there may be validity to any of IEPA's stated concerns regarding uncertainty attending the performance CCS at the TEC project, simply rejecting CCS as infeasible based on those concerns was not the only, or appropriate, course of action. IEPA erred in failing to consider adjustable BACT limits. It additionally erred in failing to require the applicant, pursuant to 40 C.F.R. § 52.21(n), to submit additional information concerning CCS as part of a complete permit application.

a. Adjustable BACT limits

As pointed out by a commenter, IEPA failed to even evaluate the possibility of an adjustable BACT limit to address any uncertainties in the implementation of CCS at TEC, despite the availability of such a limit in circumstances similar to those under consideration here. *See* RS at 133. For example, in *Hadson Power*, this Board upheld a BACT limit for nitrogen oxides (NOx) that set both a design limit and a worst-case limit in a case of the first application of a particular control technology to particular unit in this country. *Hadson Power*, 4 E.A.D. at

288-90. The permit allowed the permitting authority to revise the emission limit downward toward the design limit after operation commenced to reflect the emission rate that was demonstrated to be consistently achievable. *Id.* at 291. Similarly, the EAB has affirmed an adjustable limit, *see AES Puerto Rico*, 8 E.A.D. 324 (EAB 1999), for the control of a pollutant that would otherwise go uncontrolled, and where a new test method was to be employed, so that there was therefore little information on which to base an emission limit for that pollutant at the time the permit was finalized. *Id.* at 348-50. IEPA must evaluate similar adjustable CO_2 emission limits here, based on the demonstrated potential for sequestration, accompanied by a worst-case limit (likely based on the same principles as in the current draft permit) in the unlikely event that sequestration later is shown to be impossible or significantly limited.

IEPA rejected the possibility of adjustable BACT limits on the ground that in the cited authorities, a determination had been made that the control technology at issue constituted BACT, whereas here that determination has not been made. RS at 148. This reasoning is circular. IEPA declined to find the CCS is BACT precisely *because of* the types of implementation uncertainties that can readily be addressed via an adjustable BACT limit. IEPA should have first determined whether CCS is BACT using the site-specific analysis described above (or a comparable approach), and then determined – to the extent CCS is BACT – whether adjustable limits can be used to address any lingering uncertainty regarding implementation of this relatively new technology.

b. Requiring further information from the Applicant

Additionally, IEPA complains of lack of information that could confer a great degree of confidence in the suitability of the Mt. Simon site for sequestration, but failed to require the submission of such information as part of a complete permit application. For example, IEPA asserts that “[t]he predictive geological modeling relied upon by Schlumberger is not based on actual core sampling for the specific site being considered, so it cannot be relied upon as a conclusive evaluation of the suitability of the specific portion of the Mt. Simon formation that is targeted for sequestration.” RS at 120. But at no time does the record reflect any effort by IEPA to require submittal of such sampling data, and IEPA determined the Application to be complete without it.

IEPA erred in not requiring that the Applicant provide full information necessary to assess CCS as an available alternative. 40 C.F.R. § 52.21(n) provides that the applicant “*shall* submit *all* information necessary to perform any analysis or make any determination required under this section,” including “*any [ ] information necessary* to determine that best available control technology would be applied.” (emphases added). Thus, where a control option has been identified as available in BACT Step 1, the record must include all necessary information for determining that it is technically infeasible in order to justify rejecting it under BACT Step 2.

C. Extensive and Unchallenged Information Contained in the Permit Record Strongly Support a Finding that CCS is Feasible at TEC

Had IEPA fairly and properly evaluated CCS under the applicable standard for BACT determinations, it would have concluded that CCS is a *feasible* technology to achieve greenhouse gas reductions at the TEC and IEPA should have then proceeded through the remaining steps in a proper BACT analysis. The evidence presented by the Applicant to the Illinois General Assembly, coupled with the nature of the proposed Facility and the existence of functioning CCS projects at the same and other source types, was sufficient to require a conclusion in BACT Step 2 that CCS is technically feasible. The Board should find the IEPA erroneously eliminated limits based on BACT Step 2 considerations given that the record supports a determination that CCS is feasible, and should remand the permit to IEPA to continue its BACT analysis starting with a proper technical feasibility analysis.

As discussed in Section I.B.2, there are three aspects of CCS that need to be evaluated for feasibility according to the Guidance: capture, storage, and transport. Guidance at 35-36. Of these, capture is not an issue – IEPA acknowledges that capture is available and feasible. In the Project Summary, it states, "Separation of CO2 from the raw syngas is inherent to the production of SNG when using coal gasification and methanation. . . . because the process of converting syngas to methane in the Methanation Unit is sensitive to the CO2 content of the syngas." Project Summary at 30. Similarly, IEPA acknowledges that "[d]emonstrated technology exists for separation of CO2 from syngas, as developed in the natural gas and chemical industries," and that "CO2 is currently separated from the syngas at four coal gasification plants currently operating in the United States: Coffeyville Resources, Coffeyville Kansas (ammonia), Air Products (purified syngas), Dakota Gasification, Beulah, North Dakota (SNG), and Eastman Chemical, Kingsport, Tennessee (chemical intermediates)." *Id.* Thus, the remaining elements to be evaluated for feasibility are storage and transport.

With respect to storage, aside from presumption of feasibility flowing from the use of CCS at a similar source type (*see supra* subsection I.A.1.), the evidence is overwhelming that storage is feasible at the Mt. Simon facility. The Schlumberger 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 (CO_2) 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 CO_2 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 CO_2 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 CO_2 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 the results of a subsurface (seismic) survey, confirm that there are no faults or breaks in the lateral continuity

See Petitioners' Comments at 58-59, *citing* Ex. 53 (Feasibility Study) at 1. Moreover, as discussed in subsection I.B.1 *supra*, CCG's Class VI permit application expressly concludes that "[t]he Mount Simon Sandstone has been extensively developed for disposal and storage using Class I injection wells in Illinois and Indiana." Petitioners' Comments at 63, *citing* Ex. 58 at 37. The modeling results in the Class VI 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. *See* Petitioners' Comments at 63.

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 CO_2 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 CO_2 for permanent geologic sequestration. The CO_2 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 CO_2 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 CO_2 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)."[8]

With respect to CO_2 transport, the mere fact that CCG would be required to construct a short pipeline – approximately 30 miles – to the Mt. Simon sequestration site is insufficient grounds to conclude technical infeasibility in Step 2. In *In re Mississippi Lime*, 15 E.A.D. --, the Board rejected IEPA's Step 2 analysis as deficient, and 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. It instead 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 (*see* Petitioners' Comments at 57). All indications in the Schlumberger studies are that there are no significant obstacles (at either BACT Step 2 or Step 4)

[8] USEPA Region 5 at http://www.epa.gov/r5water/uic/adm/index.htm (December 2011), cited in Petitioners' Commenrts at 64 and n. 198.

to construction of a pipeline to Mt. Simon. The Cost Report concludes, "the target area is under and adjacent to the plant resulting in minimal pipeline cost." Petitioners' Comments at 70, citing Ex. 54 (Cost Report) at 1.[9]

The evidence in the record is overwhelming that CCS at the Mt. Simon site is feasible for BACT purposes. IEPA's determination of infeasibility at Step 2, grounded in inappropriate considerations, was clearly erroneous.

II. IEPA'S FAILURE TO CONSIDER LOW SULFUR COAL IN ITS BACT ANALYSIS VIOLATES THE U.S. CONSTITUTION

The CAA requires state agencies conducting BACT analyses to consider all available options for reducing a source's emissions, including the use of "clean fuels." 42 U.S.C. § 7479(3). IEPA unlawfully failed to do so in the BACT analysis for the TEC project. Specifically, IEPA failed to consider low sulfur coal as an alternative feedstock for gasification based on a claim that it was technically infeasible as the result of an Illinois state law favoring higher sulfur Illinois Basin coal. CCG asserted that using a dirty fuel source was required to qualify for subsidies under Illinois' Clean Coal Act, so the use of low sulfur coal is therefore technically infeasible as it would disqualify TEC from the subsidy. IEPA adopts CCG's flawed reliance on the Clean Coal Act, but goes a step further and claimed a cleaner fuel requirement would "redefine the source," a step that the agency declined to require. *See* RS 91-95; *see also* Ap., v. 1, pp. 5-6 to 5-9.

This argument is invalid for three reasons. First, the use of low sulfur coal would not redefine the source. Second, the Clean Coal Act, a state law, is preempted by the requirements

[9] In their additional BACT Step 4 analysis, Petitioners concluded that the costs of pipeline transport to Mt. Simon would be minimal. 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. *See* Petitioners' Comments at 70, *citing* Ex. 54 (Cost Study).

of the federal CAA. Third, the Clean Coal Act is a protectionist and economically discriminatory law that is unconstitutional under the Dormant Commerce Clause.

A. IEPA Must Consider Clean Fuels

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 processes and available methods, systems, and techniques." 42 U.S.C. § 7479(3).

In 1990, the U.S. Congress added "clean fuels" to the definition of BACT, 42 U.S.C. § 7479(3), in order to codify longstanding USEPA 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 CAA "promotes clean fuels with particular vigor." *In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, slip op. at 27 (EAB 2009) (hereinafter "*In re NMU*").

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). Congressional direction to applicants and permitting agencies is emphatic: in making BACT determinations, they are to give prominent consideration to fuels. EAB cases frequently underscore this charge. *In re NMU*, slip op. at 17-18 (EAB 2009); *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).

The cleaner fuel choice for the TEC is low sulfur coal. Emissions from the gasification process depend on the composition of the feedstock. The majority of the SO_2 emissions, as well as other emissions, occur during startups, shutdowns, and malfunctions when raw untreated or partially treated gases are sent directly to the flare. Petitioners' Comments at 51; RS at 105. When this occurs, the design efficiency of the gas treating system is irrelevant; it is the composition of the feedstock that directly impacts emissions. Petitioners' Comments at 51. Substances in the coal are converted into gases in the gasifier. *Id*. Organic and inorganic sulfur, for example, are converted into SO2, a gas. *Id*. If lower sulfur coals were used, the SO_2 emissions would decline significantly from 697 ton/yr to 93 ton/yr. *Id*.

B. Use of Low Sulfur Coal would Not Redefine the Source

There is a very limited exception as to when a permitting agency can decide not to evaluate the use of low sulfur coal under Step 1 of the BACT analysis – when consideration of the alternative fuel would "redefine" the source in terms of requiring the applicant to undertake a fundamentally different process and/or produce a fundamentally different product. The essential inquiry is whether the option "so substantially alter[s] the purpose or basic design of [the] proposed facility that it [would] be considered a redefinition of the source." *In re: Desert Rock Energy Company, LLC*, PSD Appeal No. 08-03 et al., Slip. Op. at 64 (EAB Sept. 24, 2009). "[W]hen evaluating an applicant's assertion that a design element is fundamental, the permit issuer should consider whether the facts underlying that assertion are better considered within the framework of steps 2 through 5 of the top-down method, rather than grounds for excluding redesign at step 1." *In re: Prairie State Generating Company*, 13 E.A.D. 1, PSD Appeal No. 05-05, Slip. Op. at 30 n.23 (EAB 2006). For instance, cost savings is not a basic or fundamental design element and is more appropriately considered at Step 4. *Id*.

IEPA rejected the consideration of clean fuels in step 1 of the BACT analysis, erroneously asserting it would "redefine the source" in two ways. RS at 91-92. First, IEPA notes that "the design of the plant as a coal gasification plant, together with its attendant use of higher sulfur bituminous coal, is recognized as a fundamental aspect of the project. If the TEC were compelled to use a [different] feedstock [ ], such a mandate would clearly re-define the purpose or basic design of the source." RS at 92. Second, IEPA states that the use of Illinois Basin coal was necessary for TEC to qualify under the Clean Coal Act, which provides financial incentives to facilities that burn coal with a minimum sulfur content of 1.7 lbs/mmBtu. RS at 92. IEPA asserts that "mandating the use of lower sulfur coal would effectively change TEC's basic design, as the project would … not fulfill the CCPSL's [Clean Coal Act's] statutory requirements."

IEPA reliance on USEPA's "redefining the source" policy is misplaced. The only limit on the CAA's clean fuel mandate recognized by the courts is where a fuel change would fundamentally change the physical scope of the project because it is co-located with a dedicated source of coal (a mine-mouth plant). *See, e.g., Sierra Club*, 499 F.3d at 655-656 ; *see also In re: Old Dominion Elec. Coop*, 3 E.A.D. 779, PSD Appeal No. 91-39 (EAB 1992). In other words, the "redefining the source" policy only prevents the permitting agency from requiring the applicant to build a fundamentally different type of facility serving a different need or producing a different product – 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 whether an agency could exclude consideration of low sulfur coal at 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 (a mine-mouth plant). *Sierra Club v. Envtl. Prot. Agency*, 499 F.3d 653, 656 (2007).

Here, the TEC is not co-located with a mine. IEPA has acknowledged that the gasifiers are "feedstock flexible." Project Summary at 24. Indeed, that is why the Summit Power Group has proposed another project consisting of an IGCC facility that would use similar Siemens gasifiers to gasify low sulfur Powder River Basin coal. Petitioner's Comments at 47.

The Seventh Circuit has already opined that minor changes involved with using low sulfur coal do not constitute redefining the source. In particular, as that Court said:

> [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; *see also Old Dominion*, 3 E.A.D. 779 ("[T]he BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."). 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.

C. IEPA's Reliance on the Clean Coal Act to Avoid its CAA Mandates Violates the Supremacy Clause

Petitioners explained in their Comments the reasons why relying on the Clean Coal Act to avoid the CAA's mandate to consider low sulfur coal under the BACT analysis is a violation of the Supremacy clause of the Constitution. Petitioner's Comments at 48.[10] IEPA argues in response that its reliance on the Clean Coal Act "did not interfere with or supplant the requirements of the [CAA]." RS at 94-96.

The Supreme Court has long held that "state laws that conflict with federal law are "without effect." *Altria Group, Inc. v. Good*, 555 U.S. 70, 76 (2008) (*quoting Maryland v. Louisiana*, 451 U.S. 725, 746 (1981). "The purpose of Congress is the ultimate touchstone in every pre-emption case." *Id.* (quotations and citations omitted). Federal laws can preempt state laws in three ways. *Hillsborough County, Fla. v. Automated Med. Labs., Inc.*, 471 U.S. 707, 712 (1985). First, Congress can expressly preempt a state law through statutory language. *Id.* Second, it can preempt all state regulation of a field by comprehensively regulating the field. *Id.* Finally, a state laws is "nullified to the extent that it actually conflicts with federal law," which

[10] While the EAB does not generally consider constitutional challenges, it will consider constitutionally-based challenges to the manner in which a statute or regulation has been applied. *In re Desert Rock*, PSD Appeal Nos. 08-03, 08-04, 08-05, 08-06 (EAB 2009) *In re Ocean State Asbestos Removal, Inc.*, 7 E.A.D. 522, 558 (EAB 1998); *In re Gen. Elec. Co.*, 4 E.A.D. 615, 627-36 (EAB 1993). In this case, IEPA's application of the Clean Coal Act to avoid CAA requirements is a violation of the law since the Clean Coal Act interferes with the methods to meet the CAA's goals. The EAB need not rule on the constitutionality of the Clean Coal Act, but merely that its application in this instance supplants the CAA by interfering with its promulgated methods.

includes both situations in which complying with both state and federal law is a physical impossibility and when a state law "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress." *Id.* Indeed, a state law is preempted "if it interferes with the methods by which the federal statute was designed to reach its goal." *Int'l Paper Co. v. Ouellette*, 479 U.S. 481, 494 (1987) (invalidating Vermont law allowing paper company to circumvent permitting requirements of the Clean Water Act). The Clean Coal Act interferes with the method that Congress chose for permitting agencies to determine BACT by assessing clean fuels, and it is therefore preempted as being in actual conflict with the CAA.

Among Congress' express purposes for enacting the Prevention of Serious Deterioration ("PSD") program is "to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision." 42 U.S.C. § 7470(5). When making such decisions to permit increased air pollution by determining BACT, Congress instructed agencies to consider what "is achievable for [a] facility through application of . . . available methods, systems, and techniques, including . . . clean fuels." Congress' intent about the method that permitting agencies must take in determining BACT is quite clear. Agencies must assess available methods, *including* clean fuels. 42 U.S.C. § 7479(3). Any deviation from this requirement is in actual conflict with the CAA and is therefore preempted under *Hillsborough* and *Ouellette*.

The Second Circuit confirmed this principle by invalidating a New York law that functionally prohibited the transfer of SO_2 trading allowances to upwind states. *Clean Air Markets Group v. Pataki,* 338 F.3d 82, 84 (2d Cir. 2003). The court found the law invalid under the *Ouellette* test, holding that it "interferes with the method selected by Congress for regulating SO_2 emissions" under Title IV of the Clean Air Act. *Id.* at 87. Like the Clean Coal Act, the law did not outright limit the ability of New York utilities to transfer their allowances, but rather required them to sell a restrictive covenant preventing subsequent transfers of allowances to upwind states. *Id.* at 88. Nevertheless, the court reasoned that "such a restrictive covenant indisputably decreases the value of the allowances," which "clearly . . . interferes with allowance trading," and "impermissibly interferes with the *methods* by which Title IV was designed to reach the goal of decreasing SO_2 emissions." *Id.* at 89 (quotations and citations omitted).

The Clean Coal Act directly interferes with Congress's chosen method for determining BACT. Congress clearly stated that PSD permits were to be issued "only after careful consideration," 42 U.S.C. § 7470(5), and that part of that assessment, the BACT determination, was to include an assessment of "clean fuels" as an emissions reduction technique. 42 U.S.C. § 7479(3). Yet IEPA claims that the TEC project meeting the definition of a "clean coal facility" under the Clean Coal Act precluded it from assessing "clean fuels" as an option. RS at 91-95. This is a straightforward case of a state law standing in the way of implementing the federal CAA in the method specified by Congress. Accordingly, there is an actual conflict between the two laws and the CAA must prevail.

D. IEPA Cannot Rely on the Clean Coal Act to Avoid Considering Low Sulfur Coal Under BACT as this Law Violates the Dormant Commerce Clause

Petitioners also pointed out in their Comments that relying on the Clean Coal Act to avoid the CAA's mandate to consider low sulfur coal under the BACT analysis violated the Dormant Commerce. Petitioners' Comments at 48. IEPA argued that its reliance on the Clean Coal Act does not violate the Dormant Commerce Clause "because [it] does not require TEC to use exclusively coal from Illinois but, rather, merely specifies the use of bituminous coal from the Illinois Basin containing a sulfur content greater than 1.7 lbs/mmBtu. The design coal for the TEC project is Illinois Basin coal, which is commonly found in Illinois, Indiana, and Kentucky.

Nothing in the state law mandates that the TEC project be restricted to Illinois coal and, for that reason, the [Clean Coal Act] does not prohibit or impede the use of coals from outside Illinois in violation of the Commerce Clause." RS at 94. IEPA is wrong. IEPA's application of that statute is unlawful because that statute violates the Constitution.[11]

1. Economically Protectionist Regulations are Unconstitutional

The "negative" or dormant aspect of the Commerce Clause "directly limits the power of the States to discriminate against interstate commerce," *Wyoming v Oklahoma*, 502 U.S. 437, 454 (1992), by "prohibit[ing] economic protectionism – that is, regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors." *New Energy Co. of Indiana v. Limbach*, 486 U.S. 269, 273-74 (1988). When state laws clearly discriminate against interstate commerce, or "amount[] to simple economic protectionism," they are struck down under "a virtually *per se* rule of invalidity." *Wyoming*, 502 U.S. at 454 *(citing Philadelphia v. New Jersey*, 437 U.S. 617, 624 (1978)); *see, e.g.*, *West Lynn Creamery Inc. v. Healy*, 512 U.S. 186 (1994) (invalidating Massachusetts law taxing all milk producers equally but transferring revenues to in-state producers as a subsidy).

Laws need not be facially discriminatory or directly protectionist to unconstitutionally restrain interstate commerce. In *Limbach*, the Supreme Court struck down a tax credit for Ohio ethanol producers, even though it extended to some out-of-state manufacturers. *See Limbach*, 486 U.S. at 274. The Court found that the law still erected an "economic barrier against competition" for some out-of-state producers, and the fact that it applied to some out-of-state

[11] As noted above, *supra* note 10, the EAB can consider constitutionally-based challenges to the manner in which a statute or regulation has been applied. In this case, IEPA's application of the Clean Coal Act to avoid CAA requirements is a violation of the law since the Clean Coal Act discriminates against interstate commerce. The EAB need not rule on the constitutionality of the Clean Coal Act, but merely that its application in this instance discriminates against the use of Power River Basin and Central Appalachian coal.

manufacturers "no more justifies disparity of treatment than it would justify categorical exclusion." *Id.* at 275. The Court further found it irrelevant that the in-state interests protected were limited in scope, noting that "where discrimination is patent . . . neither a widespread advantage to in-state interests nor a widespread disadvantage to out-of-state competitors need be shown." *Id.* at 276.

To ease what the *Limbach* Court described as "uncertainties in an already complex field," the Seventh Circuit synthesized the plethora of Supreme Court cases invalidating discriminatory and protectionist state and local laws into three categories: (1) "laws that explicitly discriminate against interstate commerce;" (2) "laws that appear to be neutral among states but that bear more heavily on interstate commerce than on local commerce; and (3) "laws that affect commerce without any reallocation among jurisdictions – that do not give local firms any competitive advantage over those located elsewhere." *Nat'l Paint & Coatings Ass'n v. City of Chicago*, 45 F.3d 1124, 1131-32 (7th Cir. 1995); *see also Illinois Rest. Ass'n v. City of Chicago*, 492 F. Supp. 2d 891 (N.D. Ill. 2007) (providing detailed discussion of each of the three categories). Laws in the first two categories, which directly discriminate against interstate commerce or have the effect of favoring in-state economic interests, are struck down as presumptively invalid. A court can uphold a law in the third category only if the local benefits provided by the law outweigh the overall effect of the statute on state and local interstate commerce. *Nat'l Solid Wastes Mgmt. Ass'n v. Meyer*, 63 F.3d 652, 657 (7th Cir. 1995).

The Supreme Court described its approach to cases in the third category as leaving open the possibility that regulations which discriminate against interstate commerce may be valid if a state proves that they "advance[] a legitimate local purpose that cannot be adequately served by reasonable nondiscriminatory alternatives." *Limbach*, 486 U.S. at 278 (finding there were reasonable nondiscriminatory alternatives to reduce harmful emissions besides using Ohio-produced ethanol). Thus, courts can uphold discriminatory and protectionist state regulations "only after finding, based on concrete record evidence, that a State's nondiscriminatory alternatives will prove unworkable." *Granholm v. Heald*, 544 U.S. 460, 493 (2005) (finding preventing underage drinking, maintaining tax revenues, and protecting public health and safety insufficient to justify statutes creating barriers to importing wine); *see also C & A Carbone Inc. v. Clarkstown*, 511 U.S. 383 (1994) (overturning waste disposal ordinance designed to efficiently use landfill space and mitigate environmental cleanup costs that did "not serve a central purpose that a nonprotectionist regulation would not"); *Kassel v. Consolidated Freightways Corp.*, 450 U.S. 662 (1981) (finding insufficient evidence in the record to justify Iowa law restricting truck length to promote highway safety).

2. State Laws Incentivizing or Encouraging the Use of Even Trivial Amounts of In-State or Regional Coal Unconstitutionally Discriminate Against Interstate Commerce

Although the test to determine whether a state law violates the dormant Commerce Clause remains murky, courts have repeatedly held that state laws mandating, incentivizing, or otherwise protecting the use of in-state coal are unconstitutional. *See, e.g.*, *Wyoming v. Oklahoma*, 502 U.S. 437, 454 (1992) (striking down Oklahoma law requiring utility to use 10% Oklahoma coal); *Alliance for Clean Coal v. Miller*, 44 F.3d 591, 595 (1995) (invalidating law incentivizing use of Illinois coal); *Alliance for Clean Coal v. Bayh*, 72 F.3d 556, 558 (1995) (finding law expediting plans for utilities using Indiana coal unconstitutional); *Gen. Motors Corp. v. Indianapolis Power & Light Co.*, 645 N.E.2d 752, 767 (Ind. Ct. App. 1995) (invalidating the same law on similar Constitutional grounds); *cf. Appalachian Voices v. State Corp. Comm'n.*, 277 Va. 509, 519-20 (2009) (upholding Virginia law allowing utilities to petition for rate adjustments at facilities equipped to burn Virginia coal only because it created "no economic incentive to use Virginia coal," but rather maintained a regime providing "a statutory disincentive to utilization of Virginia coal if use of out-of-state coal is more economical"); *Citizen Action Coal. of Indiana, Inc. v. PSI Energy, Inc.*, 894 N.E.2d 1055, 1069 (Ind. Ct. App. 2008) (upholding law that preferenced use of Illinois Basin Coal because state agency, recognizing the law to be invalid, did not actually consider the use of Indiana coal as a factor in a permitting decision); *Union Portland Cement Co. v. State Tax Comm'n*, 170 P.2d 164, 169 (Utah 1946) (finding Utah sales tax to be valid because it taxed all coal equally "regardless of where it was mined or where it was sold").

In *Wyoming*, the Supreme Court struck down a concurrent resolution of the Oklahoma legislature "requesting Oklahoma utility companies . . . to consider plans to blend ten percent Oklahoma coal," which was later amended to require one utility to use 10% Oklahoma coal. 502 U.S. at 443-44. The law ultimately resulted in utilities meeting 3.4% to 7.4% of their annual coal needs with Oklahoma coal. *Id* at 455. Citing the *Limbach* Court's analysis that the limited scope of such a facially discriminatory law was irrelevant, the Court refuted the argument that the law set aside only a "small portion" of the Oklahoma coal market, reasoning that "[t]he volume of commerce affected measures only the *extent* of the discrimination; it is of no relevance to the determination whether a State has discriminated against interstate commerce." *Id.* at 455. The Court held that Oklahoma did not meet its burden to justify the statute in terms of its local benefits and the unavailability of nondiscriminatory alternatives, brushing aside the "embellishe[d] argument that using Oklahoma's high-sulfur coal would "conserve[] Wyoming's cleaner coal for future use." *Id.* at 457.

In 1995, the Seventh Circuit invalidated two protectionist statutes enacted to force power plants to use dirty, high-sulfur coal from the Illinois Basin. In *Alliance for Clean Coal v. Bayh*, the court affirmed a district court decision overturning an Indiana law ("Indiana Law") that expedited review for utility plans which "provide[] for continued or increased use of Indiana coal," finding it to be "exactly the type of statute the dormant Commerce Clause prohibits." 72 F.3d at 558. The court reasoned that "[t]he obvious intent of the [statute] was to limit or eliminate the use of western coal in Indiana generating plants with an eye toward promoting instead the use of high sulfur coal, preferably that mined in Indiana." *Id.* The court found that "[t]he fact that the [law] does not explicitly forbid the use of out-of-state coal or require the use of Indiana coal, but "merely encourages" utilities to use high-sulfur coal by providing economic incentives does not make the [law] any less discriminatory." *Id.* at 559-60. Finally, the court dismissed the idea that it served a legitimate and compelling public interest, noting that "while we do not doubt that a healthy Indiana mining industry and a fully employed workforce may aid Indiana in achieving a low cost electrical service, this is not a legitimate justification for discrimination against interstate commerce. Protection of local, *or even regional*, industry is simply not a legislative action that is consistent with the Commerce Clause." *Id. (emphasis added).*

The *Bayh* decision came on the heels of another Seventh Circuit decision invalidating the Illinois' Coal Act, which required utilities to complete compliance plans which would be approved subject to a state agency considering "the need to use coal mined in Illinois." *Alliance for Clean Coal v. Miller,* 44 F.3d at 593. The court explained that the legislature passed the statute when "[f]aced with potentially damaging competition for the local coal industry" from low-sulfur western coal, because coal mined in the "Illinois Basin, which includes most of

Illinois and parts of Indiana and Western Kentucky Kentucky[] is relatively high in sulfur." *Id.* It stated that the "Illinois Coal Act is a none-too-subtle attempt to prevent Illinois electric utilities from switching to low-sulfur western coal," which "amounts to discriminatory state action forbidden by the Commerce Clause." *Id.* at 595-96. The court further dismissed the idea that the Act merely "encourage[d]" the local coal industry, analogizing to the complex tax-and-subsidy regime in *West Lynn Creamery* to hold that the "Illinois Coal Act cannot continue to exist merely because it does not facially compel the use of Illinois coal or forbid the use of out-of-state coal . . . even ingenious discrimination is forbidden by the Commerce Clause." *Id.* at 596. It concluded by repudiating the argument that the Act was a necessary "means of protecting Illinois citizens from economic harm from a decline in the local coal industry," finding that "[s]uch concerns do not justify discrimination against out-of-state producers." *Id.*

3. The Clean Coal Act Unconstitutionally Discriminates Against Interstate Commerce by Incentivizing Power Plants to Use Illinois Coal

The Illinois General Assembly apparently did not learn its lesson after *Miller*. In 2009 it passed the Clean Coal Act. *See* 20 ILCS 3855/1-5, 1-10, 1-75, 1-80, amended by P.A. 95-1027 (effective June 1, 2009). The Clean Coal Act subsidizes the construction of "clean coal facilities" utilizing carbon capture and storage ("CCS") and gasification technologies. 20 ILCS 3855/1-75(d)(1)-(3). One of its purposes is to "[d]evelop electric generation and co-generation facilities that use *indigenous* coal." 20 ILCS 3855/1-5(C) (emphasis added).

a. The Clean Coal Act was Enacted with the Explicitly Discriminatory Intent of Encouraging Power Plants to Use Illinois Coal

To achieve the goal of supporting indigenous coal, the Illinois legislature made a thinly-veiled attempt in the Clean Coal Act to avoid the facially discriminatory language that the

Seventh Circuit found unconstitutional in *Miller*, by requiring that "[a]ll coal used by a clean coal facility shall have high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content." 20 I.L.C.S. 3855/1-10.

Illinois State Senator Donne Trotter, who sponsored the Clean Coal Act, openly stated that the 1.7 lbs/mmBtu restriction was intended to require the use of Illinois coal. During the final Illinois Senate hearing on the law, after Trotter affirmed Senator Dale Risinger's inquiry into whether the "location of [the clean coal] project will be in Taylorville," Risinger went on to ask

> "Senator Trotter, you indicated that this will use Illinois coal. As I read the . . . bill itself, I don't see where it says Illinois coal. What it says is high volatility [sic] bituminous rank and greater than 1.7 pounds of sulfur per million Btu content. Is that the – the – is Illinois the only State that has that coal?"

Illinois Senate Transcript, 2008 Reg. Sess. No. 178, attached as Ex. 5. Trotter responded "I do not know the answer to that, sir. But that is the definition of Illinois coal." *Id.* Risinger further asked, "But it is the intent that this facility will burn Illinois coal?" Trotter responded affirmatively, saying simply, "Yes, sir." *Id.*

Other statements made by the Senators supporting the bill made clear that they believed it would require the use of Illinois coal. Risinger ultimately declared that "we need to use Illinois coal . . . so I stand in support of this project." *Id.* Senator Brady stated that "This is one of the rare opportunities where we have to match an environmentally conscious public policy with the ability to use one of Illinois' greatest resources." *Id.* Senator Demuzio, whose district includes Taylorville, proclaimed that "We in central Illinois sit on the largest bed of coal supply in the nation. And this legislation provides us here today an opportunity to vote on the . . . environmentally acceptable way . . . to bring jobs to our State." *Id.* Senator Sullivan voiced his support because "the State of Illinois has – is in a unique opportunity to – invest in the future because we have the coal reserves to do it. Not every state has that opportunity." *Id.* Finally, Senator Watson declared that "Illinois coal is going to expand . . . we have enough coal reserves here – more than Saudi Arabia. So we ought to be taking advantage of this." *Id.*

CCG similarly understood the 1.7 lbs/mmBtu provision to require the use of Illinois coal. In its permit application, it stated that "All coal found in Illinois is high volatile bituminous," and "[t]his requirement essentially eliminates western coals from consideration. All coal in Illinois meets this sulfur requirement." Updated App. (Sept. 2010) at 5-9. Meeting the definition of "clean coal facility" is vital to the project, therefore, evaluation of any fuel other than high volatile bituminous coal as part of the BACT analysis is not required." Permit Application at 5.2.3. Consultant Rodd Mackenzie, preparing a report on coal prices for the project, outright stated that "The TEC facility is required to consume, pursuant to requirements provided in [the Clean Coal Act], coal mined in Illinois," and that "Coal for the TEC gasifiers will be supplied from within Illinois pursuant to requirements provided in [Clean Coal Act]." Mackenzie Report at 8-9.

Given its discriminatory intent, the Clean Coal Act is unconstitutional under the straightforward precedent set by the Supreme Court and 7th Circuit *Wyoming, Miller,* and *Bayh*. The *Miller* court rebuked Illinois for passing a discriminatory law to protect its coal industry from competition from cleaner western coal. Yet the statements of Illinois' legislators make apparent that Clean Coal Act was intended to have the same "discriminatory affect forbidden by the commerce clause" as the Illinois Coal Act – to encourage utilities to use dirty, high-sulfur Illinois coal. Like both the Illinois Coal Act at issue in *Miller* and the Indiana Law at issue in *Bayh*, the Clean Coal Act employs subsidies and incentives to encourage the use of Illinois coal. Just as the *Miller* court found it irrelevant that the Illinois Coal Act merely "encouraged" the use of Illinois coal, and the *Bayh* court was unmoved by the Indiana Law's "voluntary" nature, Clean Coal Act is no less discriminatory merely because it is a voluntary subsidy regimen. The *Bayh* court unambiguously declared that a law whose "obvious intent" is to "limit or eliminate the use of western coal . . . with an eye toward promoting instead the use of high sulfur coal" is "exactly the type of statute the dormant Commerce Clause prohibits."

b. The Clean Coal Act Effectively Discriminates Against Interstate Commerce by Restricting Utilities to Using High Sulfur Coal Found Only in the Illinois Basin

IEPA claims that since the Clean Coal Act only requires the use of coal with a sulfur content greater than 1.7 lbs/mmBtu and not explicitly Illinois Basin coal, the Clean Coal Act does not violate the Constitution. RS at 94. The Illinois' legislature's attempt to mask its intent by requiring the use of high volatile bituminous rank coal greater than 1.7 lbs/mmBtu rather than "Illinois coal" does not make Clean Coal Act constitutional. Although this is a more clever approach than it took with the Illinois Coal Act, which the *Miller* court described as "a none-too-subtle attempt to prevent Illinois electric utilities from switching to low-sulfur western coal," the court went on to note that "even ingenious discrimination is forbidden by the Commerce Clause." As Senator Trotter explained, 1.7 lbs/mmBtu "is the definition of Illinois coal." And as Tenaska stated in its permit application, "[a]ll coal in Illinois meets this sulfur requirement." Illinois holds 75% of "high sulfur" coal above 1.68 lbs/mmBtu in the Illinois Basin, and 51% of such coal nationwide. *See* United States Geological Survey, *National Coal Resource Assessment Overview, Chapter H: Production and Depletion of Appalachian and Illinois Basin Coal Reserves* at 6 (2009), attached as Ex. 6. The Illinois Basin, comprised of Illinois, Indiana, and Western Kentucky, holds 68% of nationwide "high sulfur" coal, with the remaining high-sulfur coal reserves found in trace amounts in the Appalachian region of Eastern Kentucky, Ohio, Pennsylvania, and West Virginia. *Id.* The Appalachian states have much greater reserves of low and medium sulfur coal, while only 7% of Illinois Basin coal is classified as low and medium sulfur. *Id.* As the *Wyoming*, *Miller* and *Bayh* courts all explained, most low-sulfur coal in the United States is found in the Powder River Basin. *Id.* at 8.

Thus, although some coal meeting the Clean Coal Act's high-sulfur threshold is found outside Illinois, Senator Trotter was correct in explaining that 1.7 lbs/mmBtu is the very definition of Illinois coal. This is particularly true in light of the fact that there is little to no incentive for Appalachian states outside the Illinois Basin, which have some low and medium sulfur coal reserves, to mine their dirty, high sulfur coal, since there is almost no market for it given CAA requirements. Thus, while Clean Coal Act might appear facially neutral, it clearly has a discriminatory effect, given that it precludes the use of all western coal, and the primary coal mined and marketed in Appalachia. It effectively restrains utilities receiving Clean Coal Act subsidies to using coal mined in the Illinois Basin, rendering it unconstitutional under *National Paint & Coatings Association*'s second category as a law "that appear[s] to be neutral among states but that bear[s] more heavily on interstate commerce than on local commerce."

As the Supreme Court explained in *Limbach*, the fact that the Clean Coal Act's "economic barrier against competition" applies only to some, but not all out-of-state producers, "no more justifies disparity of treatment than it would justify categorical exclusion." The Clean Coal Act only applies to coal in the Illinois basin, which includes Illinois, Kentucky (only western Kentucky), and Indiana. It is the fact that all but three out-of-state producers are put at an economic *disadvantage* by Clean Coal Act that renders it unconstitutionally discriminatory and protectionist. It is enough that Western and Appalachian states which produce cleaner, lower-sulfur coal are put at an economic disadvantage compared to Illinois Basin states. As the

Bayh court explained, "Protection of local, *or even regional*, industry is simply not a legislative action that is consistent with the Commerce Clause."

c. Many Less Discriminatory Alternatives Exist to Advance the Clean Coal Act's Goal of Promoting Clean Coal Technology, Especially Since TEC Will Not Employ CCS Technology

In addition to its protectionist goal of promoting the use of "indigenous" coal, which is facially discriminatory, the Clean Coal Act also advances other objectives, including encouraging "the use of advanced clean coal technologies that capture and sequester carbon dioxide emissions," ILCS 3855/1-5(8), and to provide "affordable, efficient, and environmentally sustainable electric service." ILCS 3855/1-5(1). But there are a multitude of reasonable non-discriminatory alternatives to achieve these goals, rendering Clean Coal Act's discriminatory approach unconstitutional.

The Supreme Court has consistently set a very high bar for allowing discriminatory laws that advance legitimate local alternatives. The Court has been willing to uphold such laws only in the most extreme cases where there is simply no viable alternative, as in *Maine v. Taylor*, 477 U.S. 131, 138 (1986), where the harm the state needed to address were non-native fish parasites being brought into the state from outside the state, and there was no possible way to inspect fish brought into the state for the microscopic parasites. Thus, in *Limbach*, the Court struck down Ohio's protectionist ethanol subsidy after identifying non-protectionist methods of reducing harmful emissions besides using Ohio ethanol. There are clearly less discriminatory alternatives available to achieve Illinois' goal of promoting the development of gasification and CCS technology. The state could simply enact a "technology forcing" regulation, requiring that new coal fire power plants install CCS and/or use gasification. It could provide direct or indirect financial incentives and subsidies to all plants that install CCS. Critically, it could enact an identical scheme to Clean Coal Act without requiring that the use of Illinois coal. Indeed, using Illinois coal, or any particularly high sulfur coal, adds no value to the legitimate government interest in promoting the development of gasification and CCS technology – the technologies would function equally well with any type of coal.

The Supreme Court has further made clear that even very key state interests, such as preventing underage drinking in *Granholm*, highway safety in *Kassel*, and environmental cleanup costs in *Carbone,* did not justify protectionist laws where non-discriminatory alternatives existed. Thus, although promoting the development of CCS and gasification technology and providing cheap and clean electricity are valid legislative goals, because there are non-discriminatory means of doing so, the Clean Coal Act is unconstitutional. Indeed, the Seventh Circuit has already spoke clearly on the issue in *Bayh* and *Miller*, noting that the legitimate and important objectives of providing employment and economic opportunities for Illinois and Indiana citizens in the coal industries could not save the statutes at issue in each case from being struck down. Similarly, in *Wyoming*, the Supreme Court was dismissive of the idea that requiring utilities to use local, dirty-coal would save the nation's clean coal reserves for future generations. No matter how legitimate the ends Clean Coal Act is designed to achieve may be, it is unconstitutional because it uses a discriminatory means to achieve them.

III. The EAB Must Remand the Permit Because IEPA Erred in its BACT Determination for Equipment Leak Emissions

Small pieces of equipment like piping components, valves, connectors, pumps, and open-ended lines leak small amounts of the gases and liquids they handle through seals and screw fittings. These so-called "fugitive" emissions include compounds found in the streams that pass through the components – carbon monoxide ("CO"), volatile organic material ("VOM"), hydrogen sulfide ("H_2S"), total reduced sulfur ("TRS"), methane ("CH_4"), CO_2, and numerous individual hazardous air pollutants ("HAPs"), such as methanol and carbonyl sulfide ("COS"). Because such components and leaks are numerous, the aggregate emissions from them are often significant. The cost effectiveness of controlling fugitive leaks is calculated by dividing the total emissions associated with leaks from a certain type of component by the total cost of controlling leaks for that component type. Thus, the higher the volume of emissions, the more cost effective the controls.

The Taylorville facility is reported to have 24,864[12] of these components, including 18,798 connectors and 5,869 valves. [13] *See* Petitioners' Comments at 25. IEPA improperly determined in issuing the final Permit that these components would release very tiny emissions.[14] Based on this erroneous lowballing of emissions, IEPA erroneously found that controls for fugitive leaks, such as leakless technology and leak detection and repair, are not cost effective, based on the artificially low numerator in the cost effectiveness equation.

The source of the error in calculating fugitive emissions for TEC is the use of an undocumented adaptation of emission factors borrowed from another source type, organic chemical manufacturing. These emission factors, for measuring total organic compounds ("TOC"), are known as SOCMI (Synthetic Organic Chemical Manufacturing Industry) factors.[15] Moreover, the applicant and IEPA used a lower-bound variant of the SOCMI factors developed by the Texas Commission on Environmental Quality ("TCEQ"), in which the higher factors associated with ethylene are eliminated (the "SOCMI without ethylene" factors). This lower-bound variant is not endorsed in any USEPA guidance and is substantially inconsistent with it;

[12] This total excludes 115 pressure relief values that are vented to a vapor collection system and burned in the flare.
[13] Application ("AP"), v. 1, Appx. C and v. 3, Appx. D.
[14] *Id.*
[15] Ap., v. 1, Sec. 3.9, p. 3-17.

and the SOCMI without ethylene calculation has never been documented in any public record. Use of factors that are not only from a different source type, but improperly adapted to a lower-bound variant, resulted in significant underestimation of fugitive leak emissions. Had IEPA used proper assumptions, the proposed Facility's fugitive leak emissions would have been three to seven times greater than disclosed in the Application, triggering BACT for reduced sulfur compounds and rendering controls cost effective. Petitioners' Comments at 32-34.

Subsection A below discusses the overall inapplicability of SOCMI emission factors to the Facility, while subsection B specifically addresses IEPA's erroneous use of the SOCMI without ethylene variant developed by TCEQ. Subsection C addresses the errors in IEPA's cost effectiveness analysis that flowed from erroneous use of the SOCMI factors, and specifically the SOCMI without ethylene factor.

A. IEPA Erroneously Applied SOCMI Emission Factors, as TEC Is Not a SOCMI Facility

A coal gasification facility such as TEC is not a SOCMI facility, as a matter of either law or engineering. Thus, use of SOCMI emission factors is in error, and led to a gross underestimate of fugitive emissions.

1. TEC is not considered a SOCMI facility under the Clean Air Act.

The Permit itself makes abundantly clear that TEC is not a SOCMI facility. *See* Petitioners' Comments. Condition 4.9.4.a excludes the TEC components from 40 CFR 60, Subpart VVa "because the SNG and recovered sulfur produced at this plant are not products covered by the SOCMI NSPS." Condition 4.9.4.b excludes the TEC 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." EPA guidance has similarly concluded that "the IGCC system is in fact a petroleum refining process unit that is subject to Subpart CC."[16]

2. TEC's Processes Are Fundamentally Different From a SOCMI Facility In Ways That Are Very Likely To Increase Fugitive Leak Emissions

The equipment leak emission calculations are in error because IEPA failed to justify the use of adapted SOCMI emission factors for TEC and its particular physical and chemical processes. The physical and chemical composition of SOCMI and IGCC process streams must be similar to justify using the same emission factors. *See* Petitioners' Comments at 28. However, SOCMI emission factors were developed for processes used to generate synthetic organic chemicals such as acetaldehyde, acetone, and phenol,[17] 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 (*see supra* subsection III.A.1).

[16] Letter from Cynthia J. Reynolds, Director Technical Enforcement Program, USEPA Region 8, to Preston Phillips, Vice President, Hyperion Energy Center, Ref: 8ENF-AT, November 20, 2008 (attached as Exhibit 7) ("Reynolds Letter").
[17] *See* Petitioners' Comments Ex. 22 at Table 2-12.

IEPA failed to respond in the RS to Petitioners' Comments raising these differences. Indeed, the RS, despite its lengthy effort to justify the use of the adapted SOCMI factors, did not actually provide essential comparative stream composition data for any facility. RS at 51-52.

Further, IGCC plants operate continuously at higher temperatures and pressures than many batch SOCMI plants. Petitioners' Comments at 29. According to USEPA, pressure is the primary factor determining leak rate, with high line pressures increasing fugitive emissions. Petitioners' Comments Ex. 22 and USEPA Analysis of SOCMI Fugitive VOC Emissions Data, June 1981 (attached as Ex. 8) ("USEPA 1981"). Most processing units in IGCC facilities operate at higher temperature and pressures[18] than typical SOCMI processes, resulting in higher component failures and thus higher leaks. *See, e.g.*, Petitioners' Comments Ex. 22, p. 2-30. The IEPA did not respond in the RS to this comment, either.

3. SOCMI Facilities Have More Significant Incentives and Greater Ability To Reduce Fugitive Leak Emissions Than Does TEC.

SOCMI emission factors likely underestimate TEC fugitive leak emissions for at least three additional reasons. First, SOCMI facilities handle highly hazardous materials, and so historically have reduced emissions to protect workers and communities. Second, products that would leak at a SOCMI facility have a high value, increasing the financial incentive to reduce leaks. Third, SOCMI facilities consist of smaller pieces of equipment, making components more accessible for leak detection and repair. IEPA failed to adequately address any of these reasons why use of SOCMI factors is inappropriate for TEC, in either the permit documents or the RS.

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[18] *See, e.g.*, Babcock & Wilcox, Steam: Its Generation and Use, 41st Ed., 2005, Chapter 18, Coal Gasification and Higman and Van Der Burgt, Table 2-1, *cited in* Petitioners' Comments n. 113, *available at* http://books.google.com/books?id=ZUlRaUrX8IUC&pg=PA18&lpg=PA18&dq=gasifier+pressure&source=bl&ots=FluCtgO_SC&sig=HyAno4cWEFSK3WkNKHrnIVQ421Q&hl=en&sa=X&ei=TSS8T66IGYeHsgKPypEf&ved=0CFgQ6AEwAg#v=onepage&q=gasifier%20pressure&f=false. See also: http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/handbook/1.2.1.pdf.

Fugitive leak emissions from SOCMI facilities are expected to be lower than other facilities stemming from a long history of minimizing leaks in the SOCMI industry due to the hazardous nature of the process streams to workers and the surrounding community. Petitioners' Comments at 29.[19] This leak minimization has been driven in part by OSHA regulations. The chemical industry made similar comments in response to USEPA's proposal to apply refinery emission factors to SOCMI facilities:

> Many SOCMI materials were seen as more toxic and hazardous than refinery products. [Petitioners note that this is also true for coal gasification.] Industry commenters said that the toxicity of SOCMI chemicals often controls design and operating practices. As a result, SOCMI units were seen as better controlled than refineries with respect to fugitive emissions, and this level of control was expected to be reflected in lower leak frequencies and emissions."

Petitioners' Comments Ex. 22, p. 2-46. Thus, one expects lower leaks from SOCMI facilities than from other facilities that do not handle comparably toxic and hazardous substances. The RS does not respond to this issue.

In addition to health and safety concerns, there is a financial incentive at many SOCMI facilities to minimize leaks due to the high value of the intermediate process streams and products handled. *See* Petitioners' Comments at 29. TEC, in contrast, would produce syngas or electricity, relatively low value products compared to those manufactured by SOCMI facilities. Further, internal process streams at TEC are waste gases that are ultimately vented to atmosphere and have no value. Thus, the financial incentive at many SOCMI facilities that handle high value products to minimize losses far outweighs any such incentive at an IGCC facility, which has no financial incentive to prevent leaks of waste gases that have no value. So it is reasonable to expect lower fugitive emissions from the SOCMI sector than from IGCC plants. Petitioners' Comments at 29.

[19] *See also* Petitioners' Comments Ex. 22, p. 2-17, listing carcinogens and suspected carcinogens in the SOCMI category, acrylonitrile, ethylene dichloride, formaldehyde, perchloroethylene, and vinyl chloride.

The RS provides no response to this economic issue, instead placing the burden on commenters to prove this point, and arguing it is contrary to our comments on BACT without explaining how. RS at 52-53. Moreover, IEPA's statement that Petitioners cited no authority on this point is simply incorrect. The role of product value in controlling leaks as a well known economic issue considered by USEPA in establishing emission standards is reflected in a document submitted by Petitioners. In Petitioners' Comments Exhibit 22, p. 2-46, USEPA summarized industry comments on its proposal to use refinery emission factors for SOCMI facilities: "Finally, the materials produced in SOCMI were noted as of greater value than those produced in refineries. This increased value was seen as incentive for fugitive losses to be kept under better control in SOCMI than in petroleum refineries."

In addition, SOCMI facilities are largely characterized by smaller equipment and more batch processes that lend themselves more readily to control than the processes that TEC would use. Petitioners' Comments at 29. Size of equipment matters to fugitive leak emissions due to accessibility of leaking equipment and ease of control. Large complex facilities have many components that are inaccessible or dangerous to monitor and thus are exempt from Leak Detection and Repair ("LDAR") programs, compared to SOCMI facilities. The higher the number of these components, the higher the component leak emissions.

The chemical industry made similar comments in response to USEPA's proposal to use refinery emission factors for SOCMI facilities, *viz.*, "It was also pointed out that the chemical industry to a large extent is characterized by smaller equipment and more batch processes that lend themselves more readily to improved fugitive emission control. Conversely, refineries were characterized by much more strenuous conditions, larger equipment, higher temperature, and more outdoor continuous processes." Petitioners' Comments Ex. 22, p. 2-46. This distinction between SOCMI facilities and refineries, noted by the chemical industry, is identical to the situation with respect to SOCMI facilities and a coal gasification facility. A gasification facility like TEC has much bigger equipment that operates under more strenuous conditions at higher temperatures and pressures in an outdoor environment, compared to the equipment typically found in SOCMI facilities that were monitored to determine the "SOCMI without ethylene" factors.

IEPA missed the point entirely, arguing that equipment leak component emission factors are expressed on a per component basis, not a size basis. RS at 53. At issue are the impacts of large-scale vs. small-scale processes on the magnitude of emissions, not the unit of expression.

4. IEPA Relies On Unsupported General Assertions For Using SOCMI Emission Factors For TEC

In the face of these scientific and economic distinctions between TEC and SOCMI facilities, IEPA weakly responds that "USEPA itself has stated that equipment leak GHG emissions from coal gasification can be calculated according to the same methodologies used for petrochemical plants which include certain types of SOCMI facilities." RS at 50 citing an EPA TSD for petrochemical facilities. The cited document provides no support for this claim. This TSD presents several different options for calculating GHG emissions from petrochemical plants and coal gasification plants which produce chemicals, *i.e.*, methanol. However, the cited TSD does not provide guidance on how to calculate GHG emissions associated with equipment leaks, which are estimated to be less than 1 percent of the total CO_{2e} emissions from petrochemical production.[20]

Second, IEPA attempts to justify the use of SOCMI factors for a non-SOCMI facility by relying on a sentence from a USEPA fugitive estimation protocol taken out of context. IEPA

[20] While it does identify two IGCC facilities that produce chemicals, e.g., methanol, rather than fuel or electricity (at Table 6, pp. 10-11), it has nothing to say about calculating fugitive emissions from them.

cites the following statement: “for process units in source categories for which emission factors and/or correlations have not been developed, the factor and/or correlations already developed can be utilized.” RS at 48, *citing* “Protocol for Equipment Leak Emission Estimates” (Petitioners’ Comments Ex. 21), p. 2-5. But this sentence is followed by: “However, appropriate evidence should indicate that the existing emission factors and correlations are applicable to the source category in question. Criteria for determining the appropriateness of applying existing emission factors and correlations to another source category may include one or more of the following: (1) process design, (2) process operation parameters (i.e., pressure and temperature), (3) types of equipment used, and (4) types of material handled.”

IEPA claims that TEC considered these four factors, which led to the selection of SOCMI emission factors. The RS states that “[t]he basis for the selection...was laid out clearly in the Application.” RS at 48. However, the RS fails to cite any page or section where this evidence is located, and indeed there is none. Rather, the Application simply asserts without support that SOCMI emission factors are appropriate. Further, while the RS asserts that the “without ethylene” factors have been “similarly applied by agencies across the nation,” (RS at 56), the record fails to document any such case. The only such reference is an undocumented assertion that these factors were used at Summit Texas Clean Energy. RS at 49.

B. The SOCMI “Without Ethylene” Emission Factors Developed by TCEQ Are Not Appropriate for TEC

The preceding section addresses the general inapplicability of SOCMI in the context of coal gasification processes. This section addresses specifically IEPA’s error in applying an adaption of those factors developed by TCEQ.

The Permit emission calculations are based on lower-bound SOCMI without ethylene emission factors developed by TCEQ that are not endorsed in any USEPA guidance, and whose calculation has never been documented in any public record. These factors reportedly were calculated by TCEQ for process lines in SOCMI plants that contain less than 11% ethylene, but the actual calculations have never been produced. Petitioners commented that the relevance of this categorization to leaks from fugitive components in a coal gasification plant is unclear and undocumented, and there are numerous reasons why the "without ethylene" factors are inappropriate for TEC. Petitioners' Comments at 29-30. As discussed below, the SOCMI without ethylene factors artificially drive the leak rates down by excluding, for no documented or sensible reason, the higher leak rates supposedly associated with ethylene content.

As discussed in the sections below, the RS sheds no further light on this issue. Rather, it merely raises unrelated issues that confuse the record.

1. TCEQ's SOCMI "Without Ethylene" Emission Factors Are Not Accompanied by Supporting Analysis

Petitioners commented there is no support at all for the ethylene-adjusted SOCMI emission factors, which are pulled from a draft TCEQ report. Petitioners' Comments at 27, 29. TCEQ has never provided its supporting analyses. *Id.* at 29. The RS does not directly address this claim, but sidesteps it. RS at 48-49 and 57-58.

The RS points to the draft NSR Manual as its justification for relying on draft TCEQ emission factors. It asserts that the NSR Manual is "relied on as a reference in determining the sufficiency of permitting actions, although it too has not progressed beyond a 'draft.'" RS at 57.

This comparison is entirely inapt. The EAB has expressly accepted the NSR Manual has in numerous cases as reflecting EPA's interpretation of NSR regulations. However, neither USEPA nor the EAB has opined on the appropriateness of substituting undocumented TCEQ emission factors that, as explained *infra*, unjustifiably exclude all of the high emission data for documented and adopted emission factors published in connection with USEPA's established

AP-42 emission factors. If this practice is as widespread as IEPA would have us believe (*see* RS at 56 asserting that the practice is "similarly applied by agencies across the nation"), the EAB should review this issue, as it has broad national implications for air quality. Fugitive emissions have been underestimated, especially in Texas where these factors are most commonly applied, and thus they are not adequately controlled. Petitioners' Comments at 30-32.

2. The SOCMI "Without Ethylene" Emission Factors Are Without Basis and Arbitrary

The analysis that led to TCEQ's elimination of ethylene data, and the supporting spreadsheets that show the calculations and identify the emission points that were eliminated, are not in the Permit record, and have never been produced in any forum that we are aware of. The unaltered SOCMI average emission factors, on the other hand, are official USEPA emission factors, published with substantial support in AP-42, USEPA's established source of emission factors, which is accompanied by abundant underlying data, calculations, and justifications. There is simply no such track record for the "without ethylene" emission factors. The RS does not supply any data to fill this gap, but only excuses for its absence. RS at 57-58. Further, neither the TCEQ nor TEC has demonstrated why these or any SOCMI emission factors are representative of any gasification plant.

Moreover, to the extent there is any discernable basis for the factors at all, it is wrong and contrary to USEPA's analysis. According to USEPA, pressure – not ethylene concentration – is the primary factor determining leak rate. Petitioners' Comments Ex. 22 at p.2-30 and USEPA June 1981.[21] The high leak rates at ethylene facilities were due to high line pressures, which occur in many other types of facilities, not the presence of ethylene. *Id*. However, the line drawn by TCEQ between sources that should use the "without ethylene" versus those that should use

[21] *See* USEPA June 1981 Section entitled "The Effect of Line Temperature and Line Pressure" at .pdf 65-85.

the “with ethylene” factors is based on ethylene concentration, not pressure. Petitioners' Comments Ex. 25 (Correspondence with TCEQ on the derivation of the “without ethylene” factors states, “The line was drawn at streams with >80% ethylene had to use the ‘with ethylene’ factors and those with <11% volume could use the ‘without ethylene.’”)

IEPA provides no better basis in the RS to explain the drawing of this line, failing to address the pressure issue and acknowledging that SOCMI without ethylene does not even account for the similarity of other chemical compounds present to ethylene. *See* RS at 58 (“The only relevant criteria for whether SOCMI without ethylene factors are applied to a particular chemical facility type is the concentration of ethylene in the process streams and not the similarity of the chemical compounds present to ethylene.”) The record on appeal contains no information on line pressure of the TEC compared to any SOCMI facility that could be used to justify eliminating high VOC emission data in calculating fugitive leak emissions. In fact, it is well known that coal gasification facilities operate at much higher pressure than SOCMI facilities. *See* supra III.A.2.

The “without ethylene” emission factors are thus arbitrary, as they were selected based on a chemical criterion that USEPA's underlying analysis demonstrated is irrelevant.

3. SOCMI “Without Ethylene” Emission Factors Are Not a More Accurate Adaptation

The IEPA asserts the “without ethylene” emission factors are “a more accurate adaptation of the SOCMI average factors...,” (RS at 48), and “a refinement of USEPA's larger categorization.” RS at 57-58. However, USEPA analyzed the same data as TCEQ, but for good reason did not eliminate ethylene facilities from its average SOCMI emission factors, as they fell within the confidence limits for other types of SOCMI facilities. Moreover, as noted above, the high leak rates at ethylene facilities were due to high line pressures, not the presence of ethylene.

Thus, the absence of ethylene at TEC is not a basis for using “without ethylene” emission factors to TEC. Many other types of SOCMI facilities operate at high pressures, which would cause high leak rates. Accordingly, it is technically incorrect and a distortion of the data to peel off ethylene facilities and apply the residual, lower-bound SOCMI emission factors to TEC. USEPA did not subdivide the data in this way, as there were too many other factors that affected emissions – line pressure and temperature, type of component, type of process, ambient conditions, *etc*.[22]

The RS makes much of the fact that TEC emissions are predominately inorganic, thus justifying the use of low VOC “without ethylene” emission factors. RS at 51-52. However, VOCs are not the only pollutant of concern. Fugitive components leak significant amounts of inorganic pollutants, including CO, H_2S, COS, and CO_2, which are regulated under NSR and MACT rules. Comments at 26. Thus, the RTC’s argument that TEC emissions are not mostly VOCs supports our argument that emissions are underestimated and should be rejected.

4. SOCMI “Without Ethylene” Emission Factors Are Not Conservative

The RS proffers multiple arguments for the proposition that the “without ethylene” SOCMI emission factors are conservative in that they yield an upper bound estimate of fugitive component leaks from TEC, rather than a lower bound as we argued. These arguments are incorrect, and are addressed separately below.

a. Eastman Chemical

IEPA argues in the RS that the TCEQ “without ethylene” SOCMI emission factors “...are also a conservative overestimate of equipment leak component fugitive emissions.” RS at 50-51. In support, the RS states that “Eastman [Chemical] emission factors...based on actual sampling data collected at an operating gasification facility with syngas process streams containing CO,

[22] Ex. 22, p. 2-30 and USEPA 1981.

H2, and CH4 indicate leak rates that are much lower than those at ethylene facilities, which disproves the notion that leak rates are somehow directly linked with molecular size." RS at 58.

The RS cites two documents to support these arguments, in footnotes 116 and 117: (1) Major Source Operating Permit Application, PES B-334-1, for Tennessee Operations, Eastman Chemical Company's Acid Gas removal and Sulfur Recovery Plants, April 18, 2005, pages C-5 - C-17; and (2) Eastman Title V Renewal Application for AGR and SRU. RS at 50. We were unable to locate either one of these online,[23] nor are they part of the record on appeal. The only Eastman documents that are online are draft permits and permit statements.

However, based on the unsupported representations in the RS at 50, we note numerous important issues that severely undermine these representations. First, the Eastman Chemical facility does not produce either syngas or electricity, and thus is distinguishable from TEC. Second, the cited documents only address the acid gas removal and sulfur recovery plants at Eastman Chemical. However, the TEC facility additionally includes an air separation unit, raw syngas production, syngas gas conditioning, methanation, dehydration, power production, and byproduct storage and handling, making generalization of the Eastman Chemical measurements to the TEC facility inappropriate. Third, the gasification processes are different. TEC will use the Siemens gasification process (Ap., vol. 1, p. 2-6) to make syngas while the Eastman facility uses a 1983 vintage Texaco (now GE Energy) "quench" gasification process to make acetyl chemicals.[24] Fourth, while both facilities do include acid gas removal and sulfur recovery plants, the processes differ. Eastman, for example, uses a SCOT process (Power Magazine, 3/04) while

[23] The only Eastman permitting documents that we could located were at: http://www.tn.gov/environment/apc/ppo/eastman565357_631_339_421_417_630.pdf. The documents relied on in the RS are not present.

[24] Bill Trapp and others, Coal Gasification: Ready for Prime Time, Power Magazine, March 2004, http://www.clean-energy.us/projects/eastman_power_magazine.htm *See also* Eastman at http://www.clean-energy.us/success/eastman.htm and Eastman Gasification Overview, March 22, 2005, http://www.eastman.com/PublicDocs/Gasification/Eastman_Gasification_Overview.pdf.

TEC uses an unidentified TGTU (cobalt and molybdenum impregnated catalyst beds). Ap., vol. 1, p. 2-11. The record reveals nothing about the Eastman Chemical acid gas removal and sulfur recovery plants. Fifth, the leak detection and repair monitoring requirements at the two facilities appear to differ, with more stringent requirements at Eastman, RS at 50, in part justifying differences in emissions. Sixth, the Eastman factors apparently were estimated from USEPA's "correlation approach," which is a more refined emission estimating procedure than used for TEC and which requires more site-specific data.[25] Thus, relying on this data to support "without ethylene" factors is comparing apples with oranges. Finally, the record contains no evidence that the resulting Eastman emission factors were ever confirmed by actual measurement.

b. Stratified Emission Factors

IEPA argues in the RS that the "without ethylene" SOCMI factors are high, compared to EPA's stratified emission factors for SOCMI facilities as presented in the USEPA report, "Control Techniques for Fugitive VOC Emissions from Chemical Process Facilities." RS at 56. However, the RS is again comparing apples with oranges. The TEC fugitive emissions were estimated using "average" SOCMI emission factors, adjusted to eliminate ethylene facilities. Petitioners' Comments Ex. 23, at 4. The comparative data in the Control Techniques documents, on the other hand, is based on the "stratified" emission factor approach, or the so-called "leak/no-leak" approach, which is a more refined and different approach to estimating emissions that requires information on screening values. The lower emissions thus correspond to use of lower screening values.[26] This approach was not used for TEC.

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[25] USEPA, Protocol for Equipment Leak Emission Estimates, Report EPA-453/R-95-017, November 1995 ("USEPA November 1995), Sec. 2.3, especially Sec. 2.3.2 (Petitioners' Comments Ex. 21).
[26] Petitioners' Comments Ex. 21, Chapter 2.0.

c. Interim Emission Factors

IEPA also attempts to demonstrate that the "without ethylene" factors are reasonable by pointing to Table 2-20 in Petitioners' Comments Ex. 22, which contains emission factors for vinyl acetate, cumene and ethylene. It claims in the RS that the table demonstrates: (1) that ethylene plants have much higher emission rates than other SOCMI facilities and (2) that certain SOCMI process units have very low leak rates compared to EPA average SOCMI factors and even TCEQ's without ethylene factors. RS at 49. There are multiple errors in this analysis.

First, the confidence intervals around these emissions factors (in parentheses following the means in Table 2-20) indicate that they are all comparable and from the same underlying population. This is apparent when the data are displayed graphically, which shows that the confidence intervals overlap, indicating emission factors are similar in value within the confidence of the estimates. The ethylene facilities are not standouts. These data do not demonstrate that ethylene facilities are outside of the range of other SOCMI facilities, and thus that data concerning them should be discarded when evaluating emissions from SOCMI facilities.

Second, as discussed above, USEPA's detailed analysis of this data demonstrated that the higher leak rates for the ethylene facilities were due to higher line pressures, not the presence of ethylene *per se*.[27] This record contains no evidence that process lines at TEC have elevated pressures that would warrant using emission factors in which values with ethylene greater than 11% were discarded.

Finally, the Table 2-20 emission factors, published in 1982, were subsequently replaced by the average SOCMI emission factors in the 1995 Protocol report, based on much more extensive testing and analysis. Petitioners' Comments Exhibit 22 itself explains "[t]hese

[27] USEPA June 1981, section entitled, "The Effect of Line Temperature and Line Pressure," at .pdf 65 - 85.

emission factors were later recalculated." Ex. 22, Table 2-20, note b. These factors have never been used to estimate emissions for purposes of PSD and MACT permitting of either SOCMI facilities or IGCC facilities, and are merely an interim step in developing the SOCMI equipment leak emission factors published by EPA in 1995 and incorporated into AP-42.

5. Ethylene Facilities Should Not Be Eliminated from Average SOCMI Factors

As discussed above, TCEQ calculated the emission factors used to estimate equipment leak emissions from TEC using the same data used by USEPA to develop the average SOCMI emission factors, reportedly modified to remove ethylene facilities. Setting aside the issue of applicability of SOCMI factors to IGCC, Petitioners' Comments explained that it is technically incorrect to parse the underlying data in this fashion. Petitioners'' Comments at 30-31.

To justify discarding all the high values associated with ethylene facilities, IEPA claims the ethylene facilities "skewed" the average SOCMI factors to the high end due to the higher leak rates observed at these sources. RS at 49. However, USEPA did not reach this conclusion in analyzing the data set referenced by IEPA. In fact, USEPA's stated objective was to develop an average SOCMI emission factor that would apply industry wide, not to a slice of SOCMI segregated by ethylene content. *See, e.g.*, Petitioners' Comments Ex. 22, p. 2-57 (explaining the "average unit" concept).

The USEPA thoroughly analyzed the full data set in its Protocol Report and concluded that average SOCMI emission factors, *including ethylene plants*, was representative of SOCMI facilities. The USEPA chose *not* to subdivide the SOCMI category.[28] Further, EPA incorporated its analysis, based on the average SOCMI emission factor, into AP-42.[29] The "without ethylene" factors have never been formally recognized by the EPA as valid for any

[28] Petitioners' Comments Ex. 21, Sections 2.2.2.4 and 2.2.2.5 and Appendix B.
[29] *See* "Related Emission Factor Documents" at: http://www.epa.gov/ttn/chief/ap42/ch05/index.html.

SOCMI facility, let alone a coal gasification plant that produces syngas and electricity that is not even classified as a SOCMI facility.

The RS tacitly assumes normal distribution of leak rates, implying that the higher leak rates for ethylene facilities somehow “skewed” the average SOCMI emission factors, justifying tossing out the data. RS at 49. However, it is well known that environmental data, particularly emissions data, is not normally distributed, but rather is most typically log normally distributed, *i.e.*, the logarithms of the data plot as a straight line.[30] And indeed, USEPA’s analysis of the SOCMI screening data indicates that leak rates are log normally distributed. There are well established methods for determining averages and upper bounds of lognormal and other non-normal distributions that are used to address a “skewed” data distribution that do not involve indiscriminately discarding valid upper-bound data points.[31] Further, the EPA’s detailed analysis in its Equipment Leak Protocol presents no evidence that ethylene facilities skewed the SOCMI emission factors when properly analyzed.[32]

The RS also cites to Petitioners’ Comments Ex. 22, Table 2-19 as evidence that ethylene plants have elevated leak rates, and thus IEPA should discard that associated data as well. The RS states, based on this table, that ethylene facilities have “much higher percent leaking gas valves, light liquid valves, and light liquid pumps than any of the other 14 industry types evaluated...” RS at 49. This is misleading, as valves and pumps are not the major source of emissions from TEC equipment leaks. The most abundant fugitive component at TEC is flanges, which number 18,798 or 76% of the total. Flanges are the major source of TEC fugitive

[30] Petitioners’ Ex. 21, Appx. B. *See also* analytical methods described in USEPA June 1981. Section 4 of this report demonstrates the SOCMI leak rate data is log normally distributed and was appropriately analyzed without the need to toss out ethylene facilities. Section 7 presents "statistical consideration" used by EPA in analyzing fugitive component leak data.
[31] Wayne R. Ott, Environmental Statistics and Data Analysis, CRC Press, Inc., 1995; Richard O. Gilbert, Statistical Methods for Environmental Pollution Monitoring, Van Nostrand Reinhold Co., 1987; Steven P. Millard and Nagaraj K. Neerchal, Environmental Statistics with S-Plus, CRC Press, 2001.
[32] Petitioners’ Comments Ex. 21, Appendix B.

component emissions. Petitioners' Comments at 25 and 34. The RS fails to note that flanges in ethylene plants have many fewer leaking components in gas (6.2% v. 12.5%) and light liquid (6.1% v. 12.5%) services than flanges at other SOCMI facilities. Petitioners' Comments Ex. 22, Table 2-19, p. 2-32.

Further, the USEPA report itself, Petitioners' Comments Ex. 22, p. 2-30, explains: "…in almost every case examined, higher leak frequencies were associated with higher line pressure." Thus, the higher leak fractions cited by the IEPA as support for discarding ethylene plants and calculating lower SOCMI emission factors does not, in fact, support its position. The USEPA Report (Petitioners' Comments Ex. 22) does not focus on specific types of SOCMI plants, *i.e.*, ethylene, but rather on the underlying processing conditions, singling out line pressure as the key variable.

Thus, the only conclusion one can draw about ethylene plants from Ex. 22, Table 2-19 is that many ethylene plant process lines in EPA's sample operated under higher pressures than in other types of plants included in the sample. However, the record contains no evidence on the pressure of process lines serviced by fugitive components at TEC compared to pressures in SOCMI plants in general and ethylene plants in particular. Thus, there is no basis for discarding high SOCMI data based on ethylene content of TEC process streams.

6. Refinery Emission Factors Are Appropriate for TEC

Petitioners commented that gasification plants are more similar to refineries than chemical plants, warranting the use of refinery emission factors instead of SOCMI factors. Both refineries and gasification plants, 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 processes, including sour water stripping, sulfur recovery, tail gas treating, sulfur tanks and loading, thermal oxidizers, and acid gas removal systems. Petitioners' Comments at 33-34. The RS, however, argues that EPA refinery emission factors are not appropriate for TEC due to different stream compositions. RS at 51-52. Before addressing each point in this argument, we note that USEPA's only guidance on estimating fugitive component equipment leaks from IGCC plants concludes, "the IGCC system *is in fact a petroleum refining process unit*..."[33]

First, IEPA argues in the RS that syngas and SNG at TEC are "mixtures of light gases including primarily CO, H2, CO2, CH4, and water vapor." RS at 51. However, it neglects to note that there are many process streams in refineries with similar compositions, including within hydrogen plants (steam reforming, pressure swing absorption tail gas), acid gas removal, sulfur recovery plants, flexicoking waste gas, and refinery fuel gas systems that feed every combustion source (hundreds) in a refinery.[34]

In any event, even if syngas and SNG are "mixtures of light gases including primarily CO, H2, CO2, CH4, and water vapor," the USEPA's Protocol document, Petitioners' Comments Ex. 21, indicates that SOCMI factors should not be applied to these compounds. The Protocol document indicates "the emission factors and correlations presented in section 2.3 [adjusted by TCEQ to eliminate ethylene] are not intended to be applied for the used of [sic] estimating emissions of inorganic compounds."[35] All of the listed compounds are inorganic compounds except CH4. Thus, the TEC equipment leak emissions (based on emission factors in Sec. 2.3) are invalid and should be rejected.

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[33] Reynolds Letter at 5.
[34] Charles E. Baukal, Jr. (Ed.), The John Zink Combustion Handbook, CRC Press, 2001, Sec. 5.1.4.
[35] Petitioners' Comments Ex. 21 at 2-53.

C. IEPA's Erroneous Use of Inapplicable Emission Factors Resulted in the Elimination of Cost-Effective Leak Control Technology at BACT Step 4

IEPA's unjustified and incorrect application of distorted SOCMI emission factors undercuts its basis for eliminating, in BACT Step 4 based on cost, two widely used and effective fugitive emissions control technologies. As discussed in Petitioners' Comments, both leakless technology and plant-wide LDAR were eliminated in Step 4 as not cost-effective based on the erroneous low-balled and inappropriate SOCMI-derived emission estimates. *Id*. at 32-34.

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. Accordingly, 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. Here, as a consequence of the emissions underestimate resulting from misapplication of the SOCMI factors, the cost per ton to control equipment leak emissions through use of leakless technology and plant-wide LDAR was significantly overestimated, i.e., judged to be not cost effective. *See* Petitioners' Comments at 27.

To demonstrate this, Petitioners presented Table 9 in their Comments comparing estimated fugitive leak emissions at the facility using the misapplied SOCMI factors with estimates using appropriate methodologies. Petitioners' Comments at 33. As shown in the table, the Application's emissions were based on the TCEQ "without ethylene" emission factors for SOCMI "chemical plants," which yield total emissions of 342 ton/yr. This is lower than estimated using all representative emission factor options. These include two other sets of emission factors for "chemical plants" – the average USEPA SOCMI emission factors (535 ton/yr) and the TCEQ "with ethylene" SOCMI emission factor (866 ton/yr). The highest total emissions from equipment leaks (1,364 ton/yr) occur using the USEPA average refinery emission factors – as explained above, subsection III.B.6, *supra*, the appropriate emission factors for equipment leaks at TEC.

The underestimate of emissions reflected in Table 9 made the critical difference in determining whether leakless technology and LDAR are cost-effective. The Application concludes that no controls were cost-effective for equipment leaks and eliminated them all as BACT. However, 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 TEC. Petitioners' Comments at 34.

Accordingly, the EAB should remand the Permit to IEPA with instructions that it re-calculate the cost effectiveness of leakless technology and plant-wide LDAR using emission factors for equipment leaks at refineries, unless the agency can show through detailed data and engineering analysis that some other set of emission factors is more appropriate.

IV. CCG Failed to Demonstrate That Emissions From TEC Will Not Cause or Contribute to Air Pollution in Excess of the 8-Hour Ozone Ambient Air Quality Standard

In order to procure a permit, the CAA requires the owner or operator of a major emitting facility to demonstrate that "emissions from construction or operation of [the] facility will not cause, or contribute to, air pollution in excess of any . . . national ambient air quality standard for any pollutant in any area to which this part applies …" 42 U.S.C. § 7475(a)(3). *See also* 40 C.F.R. §52.21(k) ("The owner or operator of the proposed source … shall demonstrate that the allowable emissions increases from the proposed source … would not cause or contribute to air pollution in violation of: (1) Any national ambient air quality standard ["NAAQS"] in any air quality control region …").

CCG has failed to make that showing with regard to the 8-hour ozone air quality standard. 42 U.S.C. § 7475(a) ("No major emitting facility … may be constructed in any area to which this part applies" unless owner has demonstrated that facility will not result in violation of air quality standards). This issue was raised in comments. *See* Petitioners' Comments at 139-141.

Even under CCG's incomplete assessment of emissions, the proposed TEC facility will emit large amounts of NO_x (228 tpy) and VOCs (90.2 tpy). These ozone precursors react under sunlight to form ozone, a harmful pollutant that attacks the respiratory system. *See* 69 Fed. Reg. 56,697 (Sept. 22, 2004). The inappropriate qualitative assessment of ozone impacts relied on by CCG and IEPA is insufficient to ensure protection of the ozone NAAQS. The regulations require the Applicant to conduct individual source modeling of ozone impacts, which are especially important here due to serious concerns about ozone levels in adjacent areas. The Applicant must then submit this analysis to IEPA for the agency's and the public's assessment.

A. CCG Failed to Conduct, and IEPA Failed to Require, Actual Ozone Modeling

In order to assess impacts to air quality, the CAA requires applicants and agencies to use modeling. 42 U.S.C. § 7475(e)(3)(D) (requiring the Administrator to promulgate regulations specifying "each air quality model or models to be used for purposes" (emphasis added) of the PSD program, specifically the ambient air quality demonstration).[36] Applicants should estimate ambient concentrations based on the applicable air quality models, data bases, and other

[36] *See also* NSR Manual at C.24 ("Dispersion models are the primary tools used in the air quality analysis. These models estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations are used to demonstrate compliance with any applicable NAAQS or PSD increments..")

requirements specified in 40 C.F.R. Part 51, Appendix W, "Guideline on Air Quality Models." 40 C.F.R. § 52.21(l)(1). The applicant must conduct modeling for each pollutant that the proposed source would emit in significant amounts. 40 C.F.R. § 52.21(m)(1)(i)(a). USEPA regulations describe the importance and baseline requirements of modeling as follows:

- "the impacts of new sources that do not yet exist can only be determined through modeling."
- "In all cases, the model applied to a given situation should be the one that provides the most accurate representation of atmospheric transport, dispersion, and chemical transformations in the area of interest."
- "…to ensure consistency, deviations from this guide should be carefully documented and fully supported," and "consistency is not [to be] promoted at the expense of model and data base accuracy."

40 C.F.R. Part 51 Appendix W Subsections 1.b to 1.e. States and applicants are not to undertake their own independent adjustments of modeling approaches, but must seek federal approval of deviations from federal regulatory guidelines. 42 U.S.C. § 7475(e)(3)(D); 40 C.F.R. § 52.21(l)(2).

Rather than using single-source air dispersion modeling for its ozone analysis, CCG assessed ozone impacts from the proposed project using a simple set of screening tables, the "Scheffe Tables." *See* Modeling Report, pp. 3-13 – 3-15. IEPA should have rejected reliance on the Scheffe Tables, as they are inadequate to assess ozone impacts; yet the agency did not. *See* Project Summary, p. 14. Without an adequate and technically sound ozone impact analysis, CCG failed to verify compliance with the 8-hour ozone NAAQS as required by the Act.

B. Reliance on the Scheffe Tables Is Inadequate to Demonstrate Protection of the Ozone NAAQS

In comments, Petitioners detailed why it was inadequate for CCG and IEPA to rely on the Scheffe Tables. Petitioners' Comments at 139-141. Regarding the applicability of these tables, Dr. Richard Scheffe – the developer of the tables used by the Applicant – issued a memo stating that the method is, and has always been, inadequate for assessing project ozone impacts:

> 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 Georgopoulous 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.[37]

Petitioners further noted that the USEPA agrees with Dr. Scheffe that, given the current state of the art, this technique is inappropriate for assessing ozone impacts:

> 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.[38]

[37] Petitioners Comments at 140.

[38] Petitioners' Comments at 141, quoting USEPA's analyses regarding *Approval and Promulgation of Implementation Plans; Kentucky; 110(a)(1) and (2) Infrastructure Requirements for the 1997 8-Hour Ozone National Ambient Air Quality Standards*; see also 76 Fed. Reg. 41097 (July 13, 2011).

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 Tables for verifying compliance with the new 8-hour ozone NAAQS.

Rather than respond to the fact that USEPA and Dr. Scheffe have renounced the ozone impact method that CCG used and the scientific underpinnings of those decisions, IEPA offers four insufficient reasons for its reliance on the Scheffe tables, none of which alter the conclusion that CCG failed to verify compliance with the 8-hour ozone air quality standard.

1. IEPA did not receive USEPA Approval to Use the Scheffe Table Approach to Ozone Modeling for the TEC project

IEPA argues: "USEPA Region 5 has given IEPA permission in the past to use the screening tables methodology and has not objected to its use in numerous PSD permit applications where VOCs exceed 40 tons per year." RS at 282.[39] Reliance on prior permitting of unrelated projects is inappropriate. First, as a general matter, the fact that USEPA has not objected to a certain permit agency practice does not mean that USEPA has approved of that practice (in any event, as discussed in the next section, USEPA has in fact objected to use of the Scheffe Tables). *See* Letter dated April 28, 2009 to Robert Hodanbosi, Ohio EPA, from Cheryl Newton, USEPA, attached as Ex. 9. Second, the Clean Air Act regulations require CCG and IEPA to receive regional approval for a modeling approach on a case-by-case level. 40 C.F.R. § 52.21(l)(2). As noted above, such approval would include a case-by-case analysis of the appropriateness of the approach, following a process proscribed by USEPA regulations. *See* Appendix W at Subsection 3.2.2.108. In its Guidelines on Air Quality Modeling, USEPA

[39] IEPA does not cite to which prior decisions it is relying on so Petitioner cannot critique further critique why it is inappropriate to rely on those prior decisions, such as how old their decisions are.

discusses why a case-by-case approach is needed to estimate ozone impacts from individual sources:

> Choice of methods used to assess the impact of an individual source depends on the nature of the source and its emissions. Thus, model users should consult with the Regional Office to determine the most suitable approach on a case-by-case basis (subsection 3.2.2).

Appendix W to 40 CFR Part 51, Section 5.2.1.c. Further, Section 3.2.2: of the Guideline on Air Quality Models (Recommendations) states: "Determination of acceptability of a model is a Regional Office responsibility." Appendix W to 40 CFR Part 51, Section 3.2.2. There is no evidence in the record that IEPA conferred with USEPA on the method that CCG used to assess the ozone impacts, in violation of the Act and USEPA regulations.

Third, reliance on these older permit proceedings is inappropriate given USEPA and Dr. Scheffe's renouncement of the tables. It is likely that had IEPA conferred with USEPA, the Region would not have allowed the use of the Scheffe Tables as an ozone compliance method. On the issue of using the Scheffe Tables for ozone impact analysis, USEPA has stated that "[m]ore scientifically appropriate screening and refined tools are available and should be considered for use." Petitioners' Comments at 141. USEPA further has stated: "Therefore, EPA continues to believe States should consult and work with EPA Regional Offices as described in Appendix W on a case-by-case basis to determine the appropriate method for estimating the impacts of these ozone precursors from individual sources." 76 Fed.Reg. 41,088, 41,096 (July 13, 2011).[40]

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[40] *See also* Letter from Jeff Robinson, USEPA Region VI Air Permits Section Chief, to Texas Comm. On Envtl. Quality (April 14, 2009) (Robinson Letter) ("EPA has commented and provided information to TCEQ on the inaccuracies of using the Scheffe Point Source Screening Tables for determining ozone ambient impacts…The only modeling technique that would seem appropriate for this source would be a CAMx based analysis using available modeling databases.") attached as Ex. 10.

Since modeling methods are constantly improving, and because each emission source is unique, IEPA is required to consult with USEPA on a case-by-case basis to determine the best available individual source ozone modeling method. 40 C.F.R. § 52.21(l)(2). In this case, IEPA failed to do so, in violation of CAA requirements.

2. EPA Has Denounced the Use of the Scheffe Tables and Endorsed Other Modeling Methods

IEPA further argues that the "USEPA has not developed an appropriate tool for routine single source ozone modeling other than the Scheffe Tables." RS at 282. IEPA's statement is misleading, in that USEPA never endorsed the Scheffe Tables, so they cannot be considered "appropriate." As Dr. Scheffe noted: "The tables never achieved a level of EPA certification associated with EPA guideline models and consequently were not endorsed by the Agency." Petitioners' Comments at 140. Furthermore, as USEPA has found, there are appropriate screening methods and refined methods, such as the CAMx ozone modeling, available and thus that IEPA should have considered in consultation with USEPA. Petitioners' Comments at 141.[41]

The topic of individual source ozone modeling was discussed at both USEPA's 9th and 10th Conferences on Air Quality Modeling, held October 2008, and March 2012, respectively. Petitioners' Comments at 139. At the 9th Conference, USEPA stated that "Photochemical grid models provide an opportunity for credible single source modeling with source apportionment methodology."[42] Also at the 9th Conference, Environ[43] concluded that "[r]ecent advances in PGMs (photochemical grid models) make them more suitable for assessing 'single source'

[41] *See also* Robinson Letter *supra*.
[42] Baker, Kirk, USEPA, Single Source Modeling with Photochemical Models, 9th Conference on Air Quality Modeling, EPA-Research Triangle Park, NC Campus, October 2008, attached as Ex. 11.
[43] Environ is a technical and scientific consulting company that provides scientific strategic risk management assistance to an international client base.

contributions to ozone, $PM_{2.5}$, visibility and deposition."[44] At the 10th Modeling Conference, the USDA Forest Service concluded that there are "[photochemical grid models] capable of assessing single source impacts for both AQRV and ozone requirements under PSD."[45] And also at the 10th Conference, Environ developed an efficient ozone impact method for single sources in Sidney, Australia.[46]

In fact, USEPA has endorsed photochemical grid models for three projects in Region VI: (1) NRG Limestone 3, a coal-fired power plant in Texas; (2) Nucor Steel Louisiana; and (3) White Stallion in Texas. Petitioners' Comments at 141.[47] There is no reason why IEPA should allow TEC to use an inadequate ozone assessment, when Texas and Louisiana are requiring state-of-the-art photochemical grid models.

Other tools also exist to assess TEC's ozone impacts, such as back-trajectories. In a 2010 Atmospheric Environment article, Fast *et al* state: "Back trajectory analysis is a commonly-used tool for understanding how short-term variability in surface ozone depends on transport into a given location."[48] And from a 1997 paper in Atmospheric Environment: "Back trajectories have long been a standard tool in air-quality studies for characterizing source-receptor relationships in air pollution field campaigns, examining meteorological mechanisms associated with pollutant observations, and establishing time scales for various chemical reactions."[49]

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[44] Morris, Ralph, Environ, Single Source Ozone and PM Modeling, 9th Conference on Air Quality Modeling, EPA-Research Triangle Park, NC Campus, October 10, 2008, attached as Ex. 12.
[45] Anderson, Bret A., EPA/FLM Single Source LRT Demonstration Project, 10th Conference on Air Quality Modeling, EPA-Research Triangle Park, NC Campus, March 13-15, 2012, attached as Ex. 13.
[46] Morris, Ralph E., A Screening Method for Ozone Impacts of New Sources based on High-Order Sensitivity Analysis of CAMx Simulations for Sydney, 10th Conference on Air Quality Modeling, EPA-Research Triangle Park, NC Campus, March 13-15, 2012, attached as Ex. 14.
[47] *See also* Robinson Letter *supra*.
[48] Davis, Robert E., Normile, Caroline P., Sitka, Luke, Hondula, David M., Knight, David B., Gawtry, Stephen P., Stenger, Philip J., 2010, A comparison of trajectory and air mass approaches to examine ozone variability. Atmospheric Environment, 44, 64-74, attached as Ex. 15.
[49] Fast, Gerome D., Berkowitz, Carl M., 1997, Evaluation of trajectories associated with ozone transport during the 1993 North Atlantic Regional Experiment. Atmospheric Environment, 31(6), 825-837, attached as Ex. 16.

This is not an exhaustive compilation of the ozone assessment and characterization tools that were available for CCG's PSD permit modeling. However, they provide a short list of methods that USEPA has endorsed. IEPA should have consulted with the Regional Office to determine the most suitable approach for the modeling ozone impacts from TEC.

3. IEPA Failed To Address The Ozone Transport Impacts From TEC's Emissions On Ozone Non-Attainment Areas

IEPA attempted to justify CCG's use of the Scheffe Tables based on the fact that the TEC Facility is in an attainment area for ozone and that it is over 100 km away from areas with ozone problems. RS at 283. IEPA's response did not address the concerns raised in Petitioners' Comments about distant ozone nonattainment areas or the well-known problem of long-range ozone and ozone-precursor (NOx and VOC) transport. Petitioners' Comments at 139-140.

Regarding the problem of long-range ozone and ozone-precursor transport, USEPA has noted:

> Ground-level ozone tends to be a problem over broad regional areas, particularly in the eastern United States, where it is transported by the wind. When emitted, NOx reacts in the atmosphere to form compounds that contribute to the formation of ozone. These compounds, as well as ozone itself, can travel hundreds of miles across State boundaries to affect public health in areas far from the source of the pollution. Thus, cities or areas with "clean" air, those that meet or attain the national air quality standards for ozone, may be contributing to a downwind city's ozone problem because of transport.[50]

USEPA, in its Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, summarized the ozone transport problem as follows:

> The chemical reactions that create ozone take place while the pollutants are being blown through the air by the wind, which means that ozone can be more severe

[50] USEPA, Fact Sheet, Final Rule for Reducing Regional Transport of Ground-Level Ozone (Smog) and Two related Proposals (Sept. 24, 1998) at p. 3, attached as Ex. 17.

> many miles away from the source of emissions than it is at the source. 63 Fed. Reg. 57,356, 57,359 (Oct. 29, 1998).
>
> The 1990 Amendments reflect general awareness by Congress that ozone is a regional, and not merely a local, problem. As described above, ozone and its precursors may be transported long distances across State lines to combine with ozone and precursors downwind, thereby exacerbating the ozone problems downwind. The phenomenon of ozone transport was not generally recognized until relatively recently. Yet, ozone transport is a major reason for the persistence of the ozone problem, notwithstanding the imposition of numerous controls, both Federal and State, across the country63 Fed. Reg. at57,360.
>
> States generally were not able to meet the November 15, 1994 statutory deadline for the attainment demonstration and ROP SIP submissions required under section 182(c). The major reason for this failure was that at that time, States with downwind nonattainment areas were not able to address transport from upwind areas.

63 Fed. Reg. at 57,361. Given the well-documented ozone transport issue that impacts regional compliance, IEPA underestimated the scope of the problem associate with ozone.

The scientific literature is also replete with studies on long range ozone and ozone-precursor transport. A 1978 Atmospheric Environment paper regarding ozone transport in St. Louis, Missouri, states that "[o]zone transport occurs across hundreds of kilometers and crosses regional and national boundaries ('ozone transport' and 'the transport of ozone and its precursors' are used interchangeably)."[51] From a 2001 Atmospheric Environment article: "In the Northeastern US, there is concern that ozone originating from distant upwind sources significantly contributes to their ambient concentrations preventing areas from reaching attainment of the National Ambient Air Quality Standard (NAAQS) using only local controls."[52] From Atmospheric Environment, 2007: "The Ontario Ministry of the Environment in its annual report in 2002 claims that more than 50 per cent of provincial ozone levels during widespread

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[51] Karl, Thomas. R., 1978, Ozone transport in the St. Louis area. Atmospheric Environment, 12, 1421-1431, attached as Ex. 18.

[52] Schichtel, Bret A., Husar, Rudolph B., 2001, Eastern North American transport climatology during high- and low-ozone days. Atmospheric Environment, 35, 1029-1038, attached as Ex. 19.

smog episodes are due to regional-scale transport of ozone and its precursors from neighboring US states."[53] And from Environment International, 2009: "There are two major sources that contribute to ambient O_3 above background levels: local O_3 production and long-range transport of O_3 and its precursors (atmospheric constituents that produce O_3 under proper conditions)."[54]

The above citations, while providing only a glimpse of the ozone and ozone-precursor transport problem, demonstrate that IEPA erred in assuming that TEC's ozone impacts would not impact ozone nonattainment areas near Chicago and St. Louis.

4. IEPA's Response that the Scheffe Tables are Conservative is Unfounded

Finally, IEPA argues that "because of their simplicity, [the Scheffe Tables] yield a more conservative estimate than would be anticipated through photochemical modeling." RS at 282. IEPA has not provided any evidence to support this statement. *Id.* Just because a method is simple does not prove that it will provide a more conservative estimate.

IEPA also claims: "Considering that potentially affected entities and interest groups would have an objection to these tables, the American Petroleum Institute position provides some indirect confirmation of the conservative nature of the Scheffe screening tables." RS at 282. Again, this amounts to speculation from IEPA. One could just as easily make the argument that CCG's lack of objection to using the Scheffe Tables provides some indirect confirmation of the *non*-conservative nature of those tables – *i.e.*, one might well surmise that the Applicant and like-minded interest groups did not object to the use of the Scheffe Tables because this method grossly underestimates ozone impacts and hence is to these entities' advantage.

[53] Galvez, Oscar, 2007, Synoptic-scale transport of ozone into southern Ontario. Atmospheric Environment, 41, 8579-8595, attached as Ex. 20.
[54] Tong, Daniel Q., Muller, Nicholas Z., Kan, Haidong, Mendelsohn, Robert O., 2009, Using air quality modeling to study source–receptor relationships between nitrogen oxides emissions and ozone exposures over the United States. Environment International, 35, 1109-1117, attached as Ex. 21.

In sum, the failure to ensure that CCG's proposed facility will not cause or contribute to a violation of the applicable NAAQS is a clear error of law. This is also a significant policy issue that the Board should review because it is at issue that will likely surface in other proposals in the United States.

V. The EAB Should Clarify that the Permit Does Not Allow Phased Construction of the Facility

On May 8, 2012, eight days after IEPA issued the final permit for TEC, Tenaska, the parent company of CCG,[55] publicly announced that it was revising how it intended to proceed with construction of the project. The revised proposal, called the "Power Block First Plan," would initially construct a 611-megawatt (MW) combined-cycle plant that would burn natural gas but could accept substitute natural gas (SNG) from a potential future coal gasification unit. *See* Tenaska Press Release (May 16, 2012).[56] At some unspecified time in the future when market conditions improve, CCG would add a second phase of the project incorporating coal gasification equipment to convert coal to SNG, capture carbon dioxide and provide for geologic storage. *Id.* CCG would either sell the SNG on the open market or burn the SNG in the combined cycle plant. *See* Project Summary at 3. CCG is so committed to its new approach that it has amended Senate Bill 678 to reflect its revised, phased construction schedule. *See* Amendment to Senate Bill 678, attached as Ex. 22.

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[55] CCG is a joint venture of Tenaska and MDL Holding Co. to develop TEC.

[56] Petitioners have an obligation to "raise all reasonably ascertainable issues and submit all reasonably available arguments supporting … [the petitioners'] position by the close of the public comment period." 40 C.F.R. § 124.13; *see also* 40 C.F.R. § 124.19(a) (describing procedural requirements for permit review). The Power Block First Project raises significant new issues and arguments about the lawfulness of the PSD permit, which were not reasonable ascertainable or reasonably available during the public comment period as it was announced after IEPA issued the final PSD permit. Since Petitioners' issues concerning the phased permit were not reasonable ascertainable before the comment period ended, the EAB has jurisdiction to hear these arguments. *See, e.g.*, *In re Encogen Cogeneration Facility*, 8 E.A.D. 244, 249-50 & n.8 (EAB 1999); *In re Keystone Cogeneration Sys.*, 3 E.A.D. 766 (EAB 1992).

CCG has indicated that it is authorized to build phase I now and phase II later under the April 30, 2012 PSD permit, without seeking any additional permit or revision of the existing permit. IEPA has yet to opine about the legality of this new phased project. The EAB should direct IEPA to modify Permit Condition 3.2(a) to state that "[t]his permit shall become invalid if construction <u>of all phases</u> is not commenced within 18 months after this permit becomes effective." [57].

While the EAB does not typically offer advisory opinions, *In re: Desert Rock*, PSD Appeal No. 08-03 et al., it can issue such opinions when a compelling justification warrants such an opinion. *In re: Martex Farms*, 13 E.A.D. 464 (EAB 2008); *In the Matter of: Simpson Paper Company and Louisiana-Pacific Corporation,* Appeal 92-26 (EAB 1993). In this case, there is a compelling justification for the EAB to issue declaratory relief on this issue: CCG intends to construct this project under the final permit and such an approach would circumvent and undermine core requirements of the CAA, see discussion *infra*. Therefore, Petitioners request that the EAB direct IEPA to amend the commencement clause of Permit Condition 3.2(a) or to confirm in writing to EAB within thirty days from the date of its order that it has informed CCG that it may not construct TEC except as contemplated in its permit application and that if it wants to pursue a phased construction approach it should apply for a new PSD permit. *In the Matter of: Simpson Paper Company and Louisiana-Pacific Corporation* Appeal 92-26.

The CAA allows for the issuance of phased PSD permits. *See, e.g.*, *Alabama Power Co. v. Costle*, 636 F.2d 323, 410 (D.C. Cir. 1979), 40 C.F.R. § 52.21(r)(2). While there are no formal regulations governing phased permits, the EPA has held that a phased construction permit must contain both a detailed and well-defined construction schedule. *See, e.g.,* 43 Fed. Reg.

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[57] Alternatively, the EAB could direct IEPA to confirm in writing to EAB within thirty days from the date of its order that it has informed CCG that it may not construct TEC except as contemplated in its permit application.

26,388, 26,396 (June 19, 1978) ("The options are to not issue phased construction permits at all or to limit the conditions under which a phased construction may reserve an increment well into the future. The Administrator intends to implement the latter option *when plans for a phased project are certain and well-defined*.") (emphasis added); Letter from Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, USEPA, to Carl S. Pavetto, Bureau of Air Management, Connecticut Department of Environmental Protection (May 19, 1992) ("Letter from Murphy to Pavetto") (inquiring whether source had "firm plans for constructing and operating all of [its] equipment" or if the source was trying to circumvent regulations), available at http://www.epa.gov/region7/air/nsr/nsrmemos/coating.pdf; Memorandum from Edward E. Reich, Director Division of Stationary Enforcement to Diana Dutton, Director Enforcement Division—Region VI (Aug. 20, 1979) ("the plans for each phase of the project must be certain and well defined"), available at http://www.epa.gov/region7/air/nsr/nsrmemos/multifas.pdf; 40 C.F.R. § 52.21(r)(2).

The impetus for requiring a detailed and well-defined construction schedule at the outset is to avoid applicants illegally using phased PSD permits as a way to grandfather themselves into existing laws and circumvent future CAA requirements. *See, e.g.*, Letter from Murphy to Pavetto (expressing concern that a project, which would take seven years to construct, was intended to circumvent the nonattainment area New Source Review requirements by attempting to link together activities from a single construction project that are truly independent from a physical, operational, or economic standpoint). Which is why, pursuant to USEPA guidance, mutual dependence amongst all of the distinct phases is a requirement so that later phases do not get grandfathered in to compliance with older regulations. 43 Fed. Reg. 26,388, 26,396 (June 19, 1978). If the project phases are mutually dependent and one of the phases has begun construction by the applicable grandfather date, then all of the approved phases are subject to contemporary regulations. *Id.* For independent phases, *each* phase must commence construction by the grandfather date in order to avoid compliance with new regulatory requirements. *Id.*

The dependence of various phases within a project is determined on a case-by-case basis. *Id.* at 26,396 n. 6. The difference between dependent and independent phases turns on whether each phase could stand alone or whether all phases are necessary for the project to work:

> Mutually–dependent phases are those where construction of one phase necessitates the construction of the other in order to complete a given project or provide a different type (not level) of service. An example of a project with possible mutually-dependent phases is a kraft pulp mill, where all phases of construction are needed to complete the project and produce paper. On the other hand, an example of a project with possible independent phases is a three-boiler, electric power plant, where each boiler could be a mutually independent phase providing different levels of electrical power.

Memorandum from John Seitz, Director, Office of Air Quality Planning and Standards, U.S. EPA, to Regional Directors, U.S. EPA 2 (Sept. 3, 1992), available at http://www.epa.gov/ttn/nsr/gen/scan.pdf (last visited May 24, 2012).

The Power Block First Plan involves two mutually independent phases. The first phase involves the construction and operation of a natural gas-fired combined cycle plant. *See* Tenaska Press Release (May 16, 2012). This power plant would operate independently of a "potential future coal gasification unit." *Id.* The second phase of the project would consist of constructing a coal gasification unit. *Id.* CCG would either sell the SNG produced on the open market or use it on-site to generate electricity. *See* Project Summary at 3. The gasification unit is an independent unit from the combined cycle plant, as the latter can fully operate without construction of the gasification unit and CCG intends to sell a portion of the produced SNG on the market (and indeed could sell all of the SNG instead of combusting any of it in the combined cycle plant). Since the two phases are mutually independent, CCG cannot proceed with its Power Block First Project under the April 30, 2012 PSD permit.

Moreover, the newly proposed phased approach would circumvent compliance with existing regulations. On April 13, 2012, USEPA proposed new source performance standards for emissions of CO_2 for new affected fossil fuel-fired electric utility generating units (EGUs). 77 Fed. Reg. 22,392 (April 13, 2012). EPA designated TEC as a "transitional source," meaning that if CCG begins construction by April 12, 2013, it does not have to comply with the emission limitations of the proposed NSPS. 77 Fed. Reg. at 22,422 ("We believe that any of these 15 proposed sources that commences construction within 12 months of today's rulemaking proposal should be considered to have incurred substantial sunk costs and will have engaged in sufficient preconstruction planning so that the 1,000 lb CO_2/MWh standard should not apply. Any of these 15 proposed sources that do not commence construction within this period should not be considered to be similarly situated. For any of these latter sources that ultimately are constructed, the 1,000 lb CO_2/MWh standard would apply."). Under CCG's "Power Block First" proposal, it could commence construction of the natural gas combined cycle plant within 12 months of the proposed rule and build the second phase gasification unit when "market conditions improve," *see* Tenaska Press Release (May 16, 2012), thus circumventing the regulatory requirements of the electric generating unit NSPS for greenhouse gas emissions that would otherwise apply to the gasification unit. *See, e.g.*, Letter from Murphy to Pavetto (Applicant is proposing to "get a pre-approved check to cash in any time."). To prevent CCG from avoiding pending CAA requirements, the EAB should remand the permit to IEPA with instruction to modify Permit

Condition 3.2(a) to state that "[t]his permit shall become invalid if construction of all phases is not commenced within 18 months after this permit becomes effective." [58]

CONCLUSION

For the foregoing reasons, we respectfully request that the EAB review and remand IEPA's permit issued to CCG for the TEC Facility.

May 30, 2012

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[58] Alternatively, the EAB could direct IEPA to confirm in writing to EAB within thirty days from the date of its order that it has informed CCG that it may not construct TEC except as contemplated in its permit application.