Comments of Group Against Smog and Pollution, Clean Air Council, Clean Water Action, and PennEnvironment Regarding Installation Permit No. 0837-I001 for the Superior Appalachian Pipeline, LLC AC-1 Compressor Station

1. ACHD must conduct a full source determination analysis before issuing a final permit.

The draft permit record does not include any indication that Allegheny County Health Department (ACHD) has performed a source determination analysis for this facility. As will be explained in detail in the following sections, ACHD must determine whether emissions from the proposed compressor station must be aggregated with emissions from other related emission units, such as well sites that will feed into the facility. ACHD does not appear to have performed a source determination analysis, nor has the Department gathered the information necessary to carry out such an analysis.

1.1. County and federal definitions of "source."

Allegheny County air permitting regulations contain two slightly different sets of criteria to determine what emission units must be treated as a single source. In most instances:

> *"Source" means any place, structure, building, facility, equipment, installation, operation, activity, or other thing or any combination thereof:*
> *a. At, from, or by reason of which there may be emitted into the outdoor atmosphere any air contaminant;*
> *b. Which is located on one or more contiguous or adjacent properties; and*
> *c. Which is owned, operated, or allowed to be operated by the same person or by persons under common control or which is jointly owned, operated, or allowed to be operated by two or more persons, but not including motor vehicles or those emissions resulting directly from an internal combustion engine for transportation purposes or from a nonroad engine or nonroad vehicle as defined in Section 216 of the Clean Air Act.*[1]

The one relevant exception to this definition is the definition of source applicable to the County Prevention of Significant Deterioration (PSD) program. Allegheny County has incorporated the federal PSD regulations by reference.[2] The Article XXI section adopting the federal PSD regulations states that, "all of the definitions adopted by the

[1] Article XXI §2101.20 – definition of source.
[2] *Id.* §2102.07.a.

federal regulations in this subsection are hereby incorporated by reference, including those of source and major source."[3]

The U.S. Environmental Protection Agency (EPA) defines a stationary source as "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant."[4] EPA defines a "building, structure, facility, or installation" as:

> *all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual.*[5]

While the PSD definition of source applies to "any building, structure, facility, or installation,"[6] the County definition applies to "any place, structure, building, facility, equipment, installation, operation, activity, or other thing or any combination."[7] Further, the County definition does not include the "same industrial grouping" requirement. Thus the County definition of source appears to be more inclusive than the federal PSD definition.[8]

1.2. Failure to include all appropriate emission units in a source undermines the purpose of Article XXI and the federal Clean Air Act, harms public health and the environment, and may result in federal sanctions or the loss of ACHD's authority to administer its major source air permitting programs.

What emission units are considered part of a source and included in the source-wide potential to emit calculation can determine whether a source must obtain a Nonattainment New Source Review (NNSR), PSD, Title V, or minor source permit,[9] or if

---

[3] *Id.*
[4] 40 C.F.R. §§ 51.165(a)(1)(i), 52.21(b)(5).
[5] *Id.* §§ 51.165(a)(1)(ii), 52.21(b)(6); while federal Title V rules do not define "building, structure, facility, or installation," the definition of "stationary source" is to be interpreted consistent with the definition in the PSD program. Federal Operating Permits Program, 61 Fed. Reg. 34202, 34210 (July 1, 1996); *MacClarence v. EPA*, 596 F.3d 1123, 1127 (9th Cir. 2010); Memo from U.S. EPA Assistant Administrator Gina McCarthy to Regional Administrators, Withdrawal of Source Determination for Oil and Gas Industries (Sept. 22, 2009), *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/oilgaswithdrawal.pdf.
[6] 40 C.F.R. §§ 51.165(a)(1)(ii), 52.21(b)(6).
[7] Article XXI §2101.20 – definition of source.
[8] In fact, the County's more inclusive definition of source is mandated by Pennsylvania law. PADEP's regulatory definition of a non-PSD source uses similarly inclusive language and excludes the "same industrial grouping" requirement. 25 Pa. Code §121.1 – definition of facility. The Pennsylvania air pollution control act requires County air pollution ordinances to be at least as stringent as PADEP regulations. 35 P.S. § 4012(a).
[9] 42 U.S.C. §§ 7479(1), 7602(j); Article XXI §2101.20 – definition of major source; 40 C.F.R. §§ 51.165(a)(1)(iv)(A), 52.21(b)(1); 61 Fed. Reg. 34202, 34210.

the source is exempt from air permit requirements entirely.[10] If an air permitting authority adopts too narrow a definition of source, it creates a risk that major sources will be improperly classified as minor and that minor sources will be improperly classified as permit exempt. As a result, these sources would be subjected to less rigorous oversight and less demanding pollution control requirements than County or federal air permitting programs intended, and public health and the environment would bear the costs.

Further, the federal Clean Air Act and EPA regulations require state and local air permitting authorities' NNSR, PSD, and Title V programs to be at least as stringent as the federal requirements for each program.[11] Accordingly, state and local air permitting authorities' source determinations for NNSR, PSD, and Title V facilities must be consistent with or more inclusive than the federal source definition. Failure to satisfy or exceed the requirements of these federal programs may result in sanctions or jeopardize an air permitting agency's authority to administer its NNSR, PSD, and Title V permitting programs.[12]

Despite the importance of properly defining a source, the permit record for the AC-1 facility does not appear to include a source determination analysis. While a documented source determination analysis may rarely be necessary when permitting more traditional air pollution sources with well-defined boundaries, oil and gas facility source determinations are typically far less straightforward. In September 2009, EPA issued a memo (the "McCarthy Memo") clarifying the method for making source determinations for oil and gas operations.[13] The McCarthy Memo acknowledged the complexity of source determinations for the oil and gas industry, but reaffirmed that the three factors from EPA's "building, structure, facility, or installation" definition—whether facilities share a standard industrial classification major group, are under common control, and are contiguous or adjacent—must be considered on a case-by-case basis in making such determinations. In applying these three factors, McCarthy suggested permitting authorities also look to the explanations in the preamble to the 1980 revisions to the PSD/NNSR rules[14] and past determinations made by EPA regional offices.[15]

Given the complex, fact-intensive nature of oil and gas source determinations, ACHD must perform a source determination analysis whenever it is permitting a new oil or gas facility or has reason to believe an existing oil or gas operation has undergone a change that may alter a past source determination analysis.[16] Such an analysis is

---

[10] Article XXI §2102.04.a.5.
[11] 42 U.S.C. §§ 7416, 7471, 7661a(i); 40 C.F.R. § 70.1(c); 40 C.F.R. §§ 51.165(a)(1), 51.166(a)(7)(iv), 52.21(a)(1).
[12] 42 U.S.C. §§ 7413(a)(5), 7416, 7503(a)(4), 7509, 7661a(i)(4); 40 C.F.R. §§ 51.166(a)(7)(iv), 70.1(c).
[13] Memorandum from Gina McCarthy, USEPA to Regional Administrators, *Withdrawal of Source Determination for Oil and Gas Industries* (Sep. 22, 2009), *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/oilgaswithdrawal.pdf [hereinafter "McCarthy Memo"].
[14] Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans, 45 Fed. Reg. 52676, 52694–95 (Aug. 7, 1980).
[15] McCarthy Memo, *supra* note 13.

necessary to determine whether the SAP facility should be aggregated with other emission units, including but not limited to, wells and well pad emission units connected or to-be-connected to the facility, metering stations, production field tank batteries, and flowback water impoundments.

Sections 1.3-1.5 provide a more detailed explanation of EPA's source determination policy with a focus on elements that are particularly relevant to the SAP facility. In accordance with the McCarthy Memo, this discussion of source determination policy relies in significant part on EPA source determination memos and the 1980 PSD preamble. Given ACHD's obligation to administer its NNSR, PSD, and Title V programs in a manner at least as stringent as the corresponding federal requirements, and the fact that ACHD's definition of source for purposes of the minor source, NNSR, and Title V programs is more inclusive than the federal definition, ACHD must treat EPA's source determination policies as a regulatory floor rather than a model to precisely imitate.

1.3. The SAP facility and natural gas wells are part of the same SIC major group.

As discussed in Section 1.1, above, Allegheny County source determinations for minor sources, NNSR, and Title V do not include a requirement that emission units share the same SIC major group to be considered part of the same source. Thus for purposes of minor source, NNSR, and Title V permitting, SIC codes are irrelevant. However, in order to properly define a source under the PSD program, ACHD must determine whether pollutant emitting activities "belong to the same 'Major Group' (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual."[17]

The permit application for the AC-1 facility incorrectly categorizes the facility under SIC code 4922.[18] SIC code 4922 covers facilities engaged in gas storage or transmission,[19] such as compressors serving gas storage fields and transmission line boosting stations. However, the purpose of the SAP compressor station is to gather, compress, and dehydrate gas "from surrounding area wells."[20] The SIC Manual contains a separate industrial group for facilities engaged in such production or gathering activities: SIC major group 13. SIC code 1311 covers "operation of . . . field gathering lines for crude petroleum; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property."[21] SIC code 1389 includes

---

[17] 40 CFR § 52.21(b)(6); Article XXI § 2102.07.
[18] Superior Appalachian Pipeline, LLC, AC-1 Compressor Station Air Permit Application (Sep. 21, 2011) at 7 (ACHD filename 0837ip001app2011-10-04updated.pdf) [hereinafter "AC-1 application"].
[19] OSHA SIC Code Manual – 4922 Natural Gas Transmission, *available at* http://www.osha.gov/pls/imis/sic_manual.display?id=946&tab=description.
[20] AC-1 application, *supra* note 18 at 121.
[21] OSHA SIC Code Manual – 1311 Crude Petroleum and Natural Gas, *available at* http://www.osha.gov/pls/imis/sic_manual.display?id=387&tab=description.

"compressing natural gas at the field on a contract basis."[22] The SIC Manual description of major group 13 explicitly states that field gathering lines are not included in major group 49.[23] Accordingly, compressor stations primarily engaged in receiving, compressing, and processing gas from production field gathering lines are properly classified under major group 13.[24] Natural gas wells are also classified in major group 13. Well creation and maintenance activities carried out on a contract or fee basis generally fall under SIC Code 1381 or 1389.[25] Operation of gas wells and other field production equipment is classified under SIC code 1311. Thus SIC major group 13 applies to the SAP facility as well as production field and well pad emission units, meaning the "same industrial grouping" element of the PSD source determination test is satisfied.

Even if SIC code 4922 was the appropriate classification for the SAP facility, the "same industrial grouping" factor would still be satisfied because SAP functions as a "support facility" and is thus deemed to share a SIC code with the industrial activity it supports. In the 1980 PSD preamble, EPA noted:

> *Each source is to be classified according to its primary activity, which is determined by its principal product or group of products produced or distributed, or services rendered. Thus, one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC code. Support facilities are typically those which convey, store, or otherwise assist in the production of the principal product.*[26]

In the case of the SAP facility and production field emission units, the "principal product" is natural gas. The compressor station is primarily engaged in compressing, dehydrating, and conveying natural gas from nearby wells and thus fits the definition of a "support facility." Therefore, even if the SAP facility were properly categorized in SIC code 4922, the SIC code factor of the three-part PSD aggregation test would still be satisfied.[27]

---

[22] OSHA SIC Code Manual – 1389 Oil and Gas Field Services, Not Elsewhere Classified, *available at* http://www.osha.gov/pls/imis/sic_manual.display?id=391&tab=description.

[23] OSHA SIC Code Manual – Major Group 13, *available at* http://www.osha.gov/pls/imis/sic_manual.display?id=8&tab=group.

[24] *See e.g.*, Attachment 1 – WVDEP, Engineering Evaluation for Pleasants Compressor Station (Sep. 9, 2010) at 1; Attachment 2 – PADEP, Plan Approval Memo for Cumberland-Henderson Compressor Station (Oct. 6, 2011, Revised Nov. 28, 2011) at 7.

[25] OSHA SIC Code Manual – 1381 Drilling Oil and Gas Wells, *available at* http://www.osha.gov/pls/imis/sic_manual.display?id=389&tab=description; OSHA SIC Code Manual – 1389 Oil and Gas Field Services, Not Elsewhere Classified, *available at* http://www.osha.gov/pls/imis/sic_manual.display?id=391&tab=description.

[26] 45 Fed. Reg. 52676, 52695.

[27] *See e.g.* Letter from William B. Hathaway, EPA Region 6, to Allen Eli Bell, Tex. Air Control Bd., PSD Applicability Request, Valero Transmission Company (Nov. 3, 1986), *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/valeroco.pdf.

1.4. The SAP facility and associated well sites may be under common control.

To be considered a single source, emission units must also be under common control. The term "common control" is not defined in federal NNSR, PSD, or Title V regulations. EPA considers common control a fact-specific inquiry that must be conducted on a case-by-case basis.[28] It involves "the power of one business entity to affect the construction decisions or pollution control decisions of another business entity."[29] While EPA has not promulgated a formal definition of the term, the Agency states that its concept of common control is guided by the SEC's definition of control:[30] "the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through ownership of voting shares, by contract, or otherwise."[31]

Unlike the federal regulations, Article XXI does define common control:

> *"Common control", for purposes of establishing permitting requirements for sources, includes all equipment, operations, activities, and the like either fully or partially owned, operated, managed, supervised, overseen, directed, or otherwise controlled in any way by a source permit applicant or any partner, joint entrepreneur, employer, employee, wholly or partially owned subsidiary or related legal entity, parent company or related legal entity, any wholly or partially owned subsidiary or partner or joint entrepreneur of any parent company, or any other legal entity in a similar relationship to the applicant as those set forth above.*[32]

Common ownership is one straightforward means of establishing common control.[33] Thus the common control element would be satisfied if SAP (or a SAP parent, subsidiary, affiliate, partner, or joint venture business entities) own any additional emission units physically connected to the SAP facility or located in the facility's gathering area.

Additionally, emission units may be under common control even when owned by separate entities.[34] For example, common control can be established:

---

[28] Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Emission Offset Interpretative Ruling, 45 Fed. Reg. 59874, 59878 (Sept. 11, 1980).
[29] *Id.*
[30] *Id.*
[31] 17 C.F.R. § 210.1-02(g).
[32] Article XXI §2101.20 – definition of common control.
[33] Letter from Steven C. Riva, EPA Region 2 to Robert Lenney, Alcoa Massena Modernization Project (Mar. 9, 2009) at 3, *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/alcoany.pdf.
[34] *See e.g.*, Letter from Judith M. Katz, EPA Region 3 to James Salvaggio [hereinafter "Northeast Hub Source Determination"], PADEP (Jun. 10, 1992) *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/nehubltr.pdf; Letter from Richard R. Long, EPA Region 8 to Julie Wrend, Colo. Dep't of Pub. Health and Env't, Single Source Determination for Coors/Trigen (Nov 12, 1998) *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/coorstri.pdf [hereinafter "Coors/Trigen Source Determination"].

1. "through ownership of multiple sources by the same parent corporation or by a parent and a subsidiary of the parent corporation;"[35]
2. "if an entity such as a corporation has the power to direct the management and policies of a second entity, thus controlling its operations, through a contractual agreement or a voting interest;"[36]
3. "if there is a contract for service relationship between the two companies;" [37]
4. "if a support/dependency relationship exists between the two companies;"[38] or
5. if one entity "sells all of its product to the other under a single purchaser contract."[39]

In a 1995 guidance letter to Iowa DNR, EPA Region 7 provided a non-exhaustive list of additional questions air permitting authorities should consider when evaluating common control. Additional questions air permitting authorities should ask include:

- *Do the facilities share common workforces, plant managers, security forces, corporate executive officers, or board of executives?*
- *Do the facilities share equipment, other property, or pollution control equipment? What does the contract specify with regard to pollution control responsibilities of the contractee? Can the managing entity of one facility make decisions that affect pollution control at the other facility?*
- *Do the facilities share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions?*
- *Do the facilities share intermediates, products, byproducts, or other manufacturing equipment? Can the new source purchase raw materials from and sell products or byproducts to other customers? What are the contractual arrangements for providing goods and services?*
- *Who accepts the responsibility for compliance with air quality control requirements? What about for violations of the requirements?*
- *What is the dependency of one facility on the other? If one shuts down, what are the limitations on the other to pursue outside business interests?*

---

[35] Coors/Trigen Source Determination *supra* note 34 at 2.
[36] *Id.*
[37] *Id.*; Letter from John S. Seitz, "Major Source Determinations for Military Installations," (Aug. 2, 1996) at 3, *available at* http://www.epa.gov/region7/air/title5/t5memos/dodguid.pdf.
[38] Coors/Trigen Source Determination *supra* note 34 at 2.
[39] Letter from Richard R. Long, U.S. EPA Region 8 to Margie Perkins, Colorado Department of Public Health and the Env't (Oct. 1, 1999) at 2-4, *available at* http://www.epa.gov/region7/air/nsr/nsrmemos/frontran.pdf; *see also* Letter from Henry Thomas for John Seitz, EPA OQPS to John Hornback, Kentucky Division for Air Quality, Single Source Determination for Gallitan Steel Co. and Heckett MultiServ (Mar. 29, 2001) *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/hornback.pdf.

- *Does one operation support the operation of the other? What are the financial arrangements between the two entities?*[40]

At present, the permit record contains insufficient information to definitively address the common control elements mentioned above. ACHD cannot issue a final permit for the SAP facility until the Department has determined whether this facility and other production field emission units are under common control. In Section 1.6 below, commenters suggest additional information ACHD should obtain and evaluate as part of its common control analysis.

1.5. The SAP facility and associated well sites may be contiguous or adjacent.

Source aggregation decisions made by EPA Regional Offices over the last thirty years concerning whether facilities are "contiguous or adjacent" generally focus on proximity, dependency or interdependence, and the existence of a physical connection, such as a pipeline, between facilities. If one of the criteria, such as proximity, is somewhat weak, particularly strong facts in another category, such as dependency or the existence of a physical connection, can still result in a determination that emission units are contiguous or adjacent.[41]

The McCarthy Memo emphasized the fact that proximity is not necessarily the determining factor in evaluating whether facilities are contiguous or adjacent.[42] This echoes EPA's statement in the 1980 PSD preamble that, "EPA is unable to say precisely at this point how far apart activities must be in order to be treated separately. The Agency can answer that question only through case-by-case determinations."[43] To illustrate why consideration of distance alone is insufficient to determine whether sources are contiguous and adjacent, consider that EPA has concluded the following emission units were contiguous and adjacent:

- an offshore oil production platform and onshore processing plant 2.8 miles apart and separated by 1.8 miles of sea;[44]
- steelmaking operations 3.7 miles apart and separated by a lake, landfills, an interstate, and a river;[45]

---

[40] Letter from William A. Spratlin, U.S. EPA Region 7, to Peter Hamlin, Iowa Department of Natural Resources (Sep. 18, 1995) at 1-2, *available at* http://www.epa.gov/region7/air/title5/t5memos/control.pdf.
[41] Letter from Richard R. Long, EPA Region 8 to Dennis Myers, Colo. Dep't of Pub. Health and Env't, American Soda Multi-facility Source Determination (Apr. 20, 1999), *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/amersoda.pdf [hereinafter "American Soda Source Determination"] ("we believe that the distance alone does not preclude these two being considered adjacent for PSD permitting purposes.").
[42] McCarthy Memo, *supra* note 13.
[43] 45 Fed. Reg. 52676, 52695.
[44] Letter from Douglas E. Hardesty, EPA Region 10 to Mr. John Kuterbach, Alaska Dep't of Envtl. Conservation, Permitting of Forest Oil's Kustatan Production Facility and Osprey Platform (Aug. 21, 2001) *available at* http://www.epa.gov/region7/air/nsr/nsrmemos/20010821.pdf.

- a salt processing plant and brine pump station 21.5 miles apart and separated by the Great Salt Lake;[46] and
- a mine and processing plant 44 miles apart.[47]

Though the permit record currently contains very little information regarding the identity or location of emission units SAP intends to connect to the proposed compressor station, the application materials frequently refer to the proposed facility as the "Yute Compressor Station"[48] and derive emissions estimates for the facility from gas composition data from the Yute 4H well.[49] Thus it appears the wells located on the Yute well pad are among those to be connected to the SAP facility. According to the Pennsylvania Department of Environmental Protection (PADEP) well database, the Yute 4H well is located at 40.572278, -79.807056.[50] This places the Yute well pad approximately 1/3 mile from the proposed SAP facility. While distance alone does not determine whether emission units are contiguous or adjacent, the close proximity of the SAP facility and at least one of the well sites the facility will be connected to emphasizes the need for ACHD to perform a comprehensive source determination analysis.

In a 1999 guidance letter to PADEP, EPA Region 3 lists additional questions air permitting authorities should consider when determining whether emission units are contiguous or adjacent. Note that these factors overlap to some extent with those indicative of common control:

- *Was the location of the new facility chosen primarily because of its proximity to the existing facility to enable the operation of the two facilities to be integrated? In other words, if the two facilities were sited much further apart, would that significantly affect the degree to which they may be dependent on each other?*
- *Will materials be routinely transferred between the facilities? How often will this transfer take place and how much will be transferred? Will [the facility receive these materials] from anyone else? If so, how much?*
- *Will the production process itself be split in any way between the facilities, i.e., will one facility produce an intermediate product that requires further processing at the other facility, with associated air pollutant emissions?*

---

[45] Letter from Cheryl L. Newton, EPA Region 5, to Donald Sutton, Illinois EPA, Guidance on Major Modification Provisions of PSD Rules as Applied to "Re-Permitting" at Acme Steel Co. (Mar. 13, 1998) *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/acme.pdf.

[46] Letter from Richard R. Long, EPA Region 8 to Lynn R. Menlove, Utah Dep't of Envtl. Quality, Great Salt Lake Minerals Source Determination (Aug. 8, 1997) *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/util-at1.pdf.

[47] American Soda Source Determination *supra* note 41.

[48] AC-1 application, *supra* note 18 at 122, 137, 139, 146-148.

[49] *Id*. at 151.

[50] PA DEP Oil & Gas Reporting Website – Well Details – Permit # 003-21982 *available at* https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/WellDetails/WellDetails.aspx.

- *Will managers or other workers frequently shuttle back and forth to be involved actively in both facilities?*
- *What is the dependency of one facility on the other? If one shuts down, what are the limitations on the other to pursue outside business interests?*
- *Does one operation support the operation of the other? What are the financial arrangements between the two entities?*
- *Do the facilities share intermediates, products, byproducts, or other manufacturing equipment? Can the new source purchase raw materials from and sell products or byproducts to other customers? What are the contractual arrangements for providing goods and services?*
- *Do the facilities share equipment, other property, or pollution control equipment? What does the contract specify with regard to the pollution control responsibilities of the contractee? Can the managing entity of one facility make decisions that affect pollution control at the other facility?*
- *Who accepts the responsibility for compliance with air quality control requirements? What about for violations of the requirements?*
- *Do the facilities share common workforces, plant managers, security forces, corporate executive officers or board executives?*
- *Do the facilities share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions?*[51]

At present the permit record contains insufficient information to definitively address the contiguous and adjacent factors mentioned above. For instance, in the fall of 2010, EPA Region 5 determined a gas sweetening plant and connected production wells, some of which were over 8 miles from the sweetening plant, were functionally interdependent and thus contiguous and adjacent.[52] It appears the SAP facility is intended to serve as part of a system with a similar functional interdependency: providing needed compression services for area gas wells as their wellhead pressure declines over time.

ACHD cannot issue a final permit for the SAP facility until the Department has determined whether this facility and other production field emission units are contiguous or adjacent. In the following section, commenters suggest additional information ACHD should obtain and evaluate as part of its common control analysis.

---

[51] Northeast Hub Source Determination *supra* note 34 at 2-4.

[52] Letter from Cheryl L. Newton, EPA Region 5 to Scott Huber, Summit Petroleum Corp., (Oct.18, 2010) at 6, *available at* http://epa.gov/region07/air/title5/t5memos/singler5.pdf.

1.6. Additional information is necessary to perform a source determination analysis.

Much of the additional information necessary to perform a source determination can be gleaned from the discussion and references in Sections 1.2-1.5. In addition, Commenters suggest ACHD consider the questions PADEP posed to MarkWest Liberty Midstream and Resources, LLC regarding the relationship between its Houston Gas Processing Plant and connected natural gas compressor stations,[53] and the EPA administrator's guidance to the Colorado Department of Health and Environment (CDPHE) regarding a proper source determination analysis for the Frederick Compressor Station and related gas wells:

> *In order to do a thorough analysis, I recommend that CDPHE evaluate Kerr-McGee's complete system map showing all emission sources owned or operated by the Company in the Wattenberg gas field . . . determine whether the various pollution emitting activities are contiguous or adjacent to, and under common control with, the Frederick Compressor Station. . . . I also recommend that CDPHE obtain from Kerr-McGee/Anadarko a flow diagram showing the movement of gas from the well sites to the various facilities in the Wattenberg field operated by both Kerr-McGee/Anadarko and other companies in the field, so that CDPHE may determine the nature of the sources' emissions and determine whether or not the process units associated with those emission sources are interdependent on the operation of the Frederick Compressor Station.*[54]

Specific information ACHD should request from SAP includes, but is not limited to:

1. A map depicting:
    a. all existing and anticipated future emission units that are or will be connected to the SAP compressor station, including well pad emission units, pits, impoundments, tanks, and metering stations; and
    b. the distances between these units.

2. Owner and operator information for the emission units identified in item 1.

3. A diagram and process flow description depicting:

---

[53] Attachment 3 – Letter from George Jugovic, PADEP to John C. Mollenkopf, MarkWest Energy Partners, L.P. (Oct. 6, 2010).

[54] *In re* Kerr-McGee/Anadarko Petroleum Corporation, Frederick Compressor Station, Order Granting Petition for Objection to Permit, Petition No. VIII-2008-02 (Oct. 8, 2009) at 8, *available at* http://www.epa.gov/region07/air/title5/petitiondb/petitions/anadarko_response2008.pdf. (CDPHE's revised source determination once again concluded that the well sites and compressor station should not be considered a single source and EPA denied a subsequent Title V Petition challenging CDPHE's determination. *In re* Anadaroko Petroleum Corp. Frederick Compressor Station, Order Responding to Petitioners' Request that the Administrator Object, Petition No. VIII-2010-4 (Feb. 2, 2011) *available at* http://www.epa.gov/region07/air/title5/petitiondb/petitions/anadarko_response2010.pdf).

a. the existing and anticipated physical connections between gas field emission units,
b. truck loadout points,
c. the composition of the materials being transported at each point in the process (e.g. wellhead gas, sales gas, produced water), and
d. direction(s) of material movement.

4. Copies of all contractual agreements between SAP (or SAP parent, subsidiary, affiliate, partner, or joint venture business entities) and parties that own, operate or otherwise control emission units that are associated with, physically connected to, or otherwise operationally related to the SAP facility.

   For instance, during an August 2011 quarterly earnings call, a representative of Unit Corporation (SAP's parent company[55]) stated that "in the Appalachian region, we have signed a letter of intent with producer to begin the construction of the Pittsburgh Mills gathering system in Allegheny and Butler Counties in Pennsylvania [and are] working with the producer to finalize the gathering agreement."[56] As stated in section 1.4 above, common control can be established by contractual agreements. ACHD cannot evaluate common control without first reviewing these and any other similar agreements to which SAP (or a related business entity) is a party.

5. Whether the SAP facility will share employees with the owners or operators of other emission units associated with the SAP facility.

6. Can SAP (or SAP parent, subsidiary, affiliate, partner, or joint venture business entities) exert any operational control over other emission units associated with the SAP facility? For example:
   a. Will SAP provide maintenance, or security services for other emission units?
   b. Are there any circumstances under which SAP may shut in or reduce flow from a connected well?

7. Similar to #6, may the owners or operators of other emission units associated with the SAP facility exert operational control over the SAP facility?

8. Is the SAP facility subject to any contractual limits on its ability to provide compression services? For instance:
   a. Do any contractual agreements restrict the SAP facility's ability to receive gas from wells or pipelines owned or operated by entities who are not a party to that contract?

---

[55] Superior Appalachian Pipeline, LLC, Compliance Review Form (Jan. 16, 2012) PDF at 6 (ACHD filename 0837ip001c2012-01-17additional.pdf).
[56] Unit Corporation, *Unit CEO Discusses Q2 2011 Results – Earnings Call Transcript* (Aug. 2, 2011), *available at* http://seekingalpha.com/article/283954-unit-ceo-discusses-q2-2011-results-earnings-call-transcript.

b. Do any contractual agreements obligate SAP to provide a minimum compression capacity for a specific well owner or operator?

9. Are wells in the SAP facility gathering area subject to any contractual limits on their ability to direct gas to non-SAP facilities?

10. What factors did SAP consider in the process of selecting the SAP facility location?

2. SAP's compressor engine BACT analysis is inadequate.

SAP's compressor engine Best Available Control Technology (BACT) analysis fails to identify and evaluate all potential control technologies. A proper BACT analysis must include evaluation of electric powered compressor engines[57] and rich burn engines equipped with Non-Selective Catalytic Reduction (NSCR). Rich burn engines equipped with NSCR (a.k.a. "three-way catalysts") are routinely capable of achieving nitrogen oxide (NOx) emission rates of .2 g/bhp-hr[58]—a 60% reduction from SAP's proposed BACT.

While "[h]istorically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives . . . . this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. . . . [T]here may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis."[59] The workshop manual further notes that "inherently lower emitting processes/practices" are among the categories of control techniques "[t]he top-down BACT analysis should consider."[60]

The Environmental Appeals Board articulated the test to determine what constitutes a "redefinition" of a source in *In re: Desert Rock Energy Company, LLC*:

> [T]he permit applicant initially "defines the proposed facility's end, object, aim, or purpose – that is the facility's basic design," although the applicant's definition must be "for reasons independent of air permitting." The inquiry, however, does not end there. The permit issuer . . . should take a "hard look" at the applicant's determination in order to discern which design elements are inherent for the applicant's purpose and which design elements "may be changed to achieve pollutant emissions

[57] Al Armendariz, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements (Jan. 26, 2009) at 29-31, *available at* http://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf.
[58] Attachment 9 – PADEP, Review of Plan Approval Application for Welling Compressor Station (Dec. 29, 2010, revised Jan. 12, 2011) at 5-6.
[59] USEPA, Draft NSR Workshop Manual (Oct. 1990) at b.13, *available at* http://www.epa.gov/region07/air/nsr/nsrmemos/1990wman.pdf , [hereinafter "NSR Workshop Manual"]
[60] *Id.* at b.10

> reductions without disrupting the applicant's basic business purpose for the proposed facility," while keeping in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility.[61]

The purpose of the SAP facility is to compress and dehydrate natural gas.[62] Use of electric or rich-burn engines would do nothing to alter that purpose and thus should be included in the BACT analysis.

Even if the impermissibly narrow scope of control technologies SAP evaluated were acceptable, SAP's BACT analysis remains inadequate. The table below compares the proposed formaldehyde (HCHO), non-methane non-ethane hydrocarbon (NMNEHC), and carbon monoxide (CO) emissions from the SAP engines to two other southwestern Pennsylvania facilities operating Caterpillar G3516B engines equipped with oxidation catalysts.

	SAP[63]		Shamrock[64]		Welling[65]	
Pollutant	Controlled g/bhp-hr	% Reduction	Controlled g/bhp-hr	% Reduction	Controlled g/bhp-hr	% Reduction
NMNEHCs	0.24	50%	< 0.10	> 79%	0.12	75%
CO	0.17	93%	< 0.17	> 93%	0.12	95%
HCHO	0.44	76%	< 0.09	> 79%	0.04	90%

The Shamrock and Welling facilities demonstrate that it is technically and economically feasible to achieve lower emission rates than SAP proposes. According to EPA's NSR Workshop Manual, for each technically feasible control technology identified that is capable of operating within a range of control efficiencies, "the most effective level of control must be considered in the BACT analysis."[66] Further:

> *[W]hen reviewing a control technology with a wide range of emission performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise.*[67]

---

[61] *In re: Desert Rock Energy Company, LLC*, PSD Appeal No. 08-03 et al., Slip. Op. at 64 (EAB Sep. 24, 2009) (citations omitted).
[62] AC-1 application, *supra* note 18 at 121
[63] *Id*. at 153.
[64] Attachment 4 – Vendor data for CAT G3516B engine and oxidation catalyst, from Laurel Mountain Midstream, LLC, Shamrock Compressor Station Plan Approval Application (Nov. 2, 2011).
[65] Attachment 5 – Vendor data for CAT G3516B engine and oxidation catalyst, from MarkWest Liberty Midstream and Resources LLC, Welling Compressor Station Plan Approval Application (Nov. 24, 2010).
[66] NSR Workshop Manual *supra* note 59 at b.23-b.24.
[67] *Id*. at b.23.

SAP's BACT analysis does not satisfy the Article XXI BACT requirement[68] because it: (1) does not evaluate all potential control technologies, (2) does not evaluate the most effective level of control achievable via use of oxidation catalysts; and (3) does not provide any evidence to suggest the SAP facility is distinct from facilities subject to lower emission rates. Thus the BACT analysis must be revised to include consideration of NSCR-equipped rich burn engines and electric engines. If these technologies are properly excluded in later steps of the analysis, the SAP compressor engines still must achieve emission rates comparable to or lower than those achieved at Shamrock and Welling. Possible means to achieve these lower emission rates include the addition of a third catalyst element[69] or use of a more effective oxidation catalyst model.

2. The compressor engine VOC PTE calculations exclude multiple compounds categorized as VOCs, resulting in significant underestimation of actual VOC emissions.

The emission calculations for the 5 Caterpillar G3516B engines fail to account for multiple pollutants classified as volatile organic compounds, thus resulting in significant underestimation of VOC emissions.

The compressor engine emissions calculations are based on an assumed uncontrolled VOC emission rate of 0.48 g/bhp-hr.[70] The source for the uncontrolled VOC emission rate is a Caterpillar G3516B engine specification sheet, which lists a 0.48 g/bhp-hr emission rate for "NMNEHCs (VOCs)."[71] However, NMNEHCs are not synonymous with VOCs. Most notably, this term does not include photochemically reactive aldehydes and alcohols. In fact, the engine specification sheet explicitly states that aldehydes are excluded from the 0.48 g/bhp-hr emission rate.[72]

Engine specification sheets often use a definition of VOCs more limited than the 40 C.F.R. § 51.100(s) VOC definition. The apparent reason for this practice is that the VOC emission limits contained in new source performance standards (NSPS) subpart JJJJ for spark ignition IC engines exclude formaldehyde[73] and underestimate emissions of other oxygenated organic compounds.[74]

While it is permissible to exclude formaldehyde for the purpose of determining compliance with the engine NSPS, all VOCs, as defined in 40 C.F.R. § 51.100(s), must be considered for such purposes as determining Title V/NSR applicability and developing

---

[68] Article XXI §2102.04.b.6.
[69] AC-1 application, *supra* note 18 at 153.
[70] ACHD, Permit Review Document for Superior Appalachian Pipeline, LLC, IP # 0837-I001 (Feb. 2, 2012) at 4 [hereinafter ACHD Permit Review Document].
[71] AC-1 application, *supra* note 18 at 90.
[72] *Id*. at 92, n. 8.
[73] 40 C.F.R. § 60.4244(f) ("For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included.").
[74] Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and NESHAP for Reciprocating Internal Combustion Engines, 73 Fed. Reg. 3568, 3579-80 (Jan. 18, 2008).

ozone control strategies. Thus ACHD must revise the compressor engine VOC limits and site-wide PTE calculations to account for all VOCs covered by 40 C.F.R. § 51.100(s). Compounds omitted or potentially omitted from the 0.48 g/bhp-hr emission rate include formaldehyde, acetaldehyde, acetone, acrolein, methanol, phenol, and isobutyraldehyde.

3. The permit must account for emissions from compressor cold starts and blowdowns.

SAP's permit application does not account for emissions from compressor engine cold starts and blowdowns. A blowdown occurs when a compressor engine is shut down and de-pressurized. For example, the application for a Fayette County compressor station estimates blowdown emissions from 6 oxidation-catalyst-equipped Caterpillar G3516B engines at 113.13 tons per year (TPY) methane, 1.81 TPY VOCs, and 0.54 TPY HAPs.[75] This application also estimates cold start emissions for 7 oxidation-catalyst-equipped Caterpillar G3516B engines at 10.77 TPY methane, 0.15 TPY VOC, and 0.05 TPY hazardous air pollutants (HAPs).[76] Neither SAP nor ACHD appear to have calculated engine cold start or blowdown emissions. These emissions must be accounted for in the final permit.

4. The permit must account for emissions associated with produced water storage and transport.

SAP's permit application does not account for emissions from produced water storage tank venting or produced water truck loadout. The applicant states that "[l]iquids (water) from the inlet separator are stored in two (2) 300-bbl water storage tanks with minimal emissions until unloaded via tanker truck."[77] However, the applicant provides no support for its claims that produced water tank emissions will be minimal. The applicant also fails to provide an emissions estimate for truck loading, despite having acknowledged that these emissions will be greater than emissions from tank venting.

VOC emissions from even relatively low vapor pressure produced water tank venting and truck loadout can be significant.[78] Further, it is relatively straightforward to estimate emissions from both tank venting[79] and truck loadout.[80] Thus it is not unduly burdensome to ask the applicant to provide emissions calculations to support its claim that these emissions sources are insignificant.

---

[75] Attachment 6 – Facility emissions calculations, from Laurel Mountain Midstream, LLC, Shamrock Compressor Station Plan Approval Application (Nov. 2, 2011) at 9 [hereinafter "Attachment 6"].
[76] *Id.*
[77] AC-1 application, *supra* note 18 at 121.
[78] Attachment 6 *supra* note 75 at 14. Attachment 7 – Facility emissions calculations from Keystone Midstream Services, LLC Bluestone Compressor Station Plan Approval Application (Dec. 27, 2010) at 17-19.
[79] EPA AP-42, Chapter 7.1; EPA TANKS software, *available at* http://www.epa.gov/ttnchie1/software/tanks/index.html.
[80] EPA AP-42, Chapter 5.2.

5. ACHD has not accounted for all greenhouse gas emissions from this facility.

The applicant and ACHD have failed to account for all greenhouse gas (GHG) emissions from the proposed facility. SAP's permit application includes a summary of facility GHG emissions; [81] however, this summary only lists GHG estimates for the compressor engines and dehydrator reboilers. It does not account for fugitive GHG emissions or emissions from the glycol regenerator condensers.

SAP has provided VOC emissions estimates for fugitives.[82] Those estimates, combined with the gas analysis SAP has provided suggest fugitive methane emissions of approximately 100 TPY. SAP's Glycalc runs include methane emissions from the condenser-controlled dehydrator regenerators.[83] The fugitive and condenser GHG emissions must also be accounted for in the facility-wide GHG calculation.

In addition, the applicant's carbon dioxide (CO_2) calculations for the compressor engines, which ACHD relies on in its permit review document,[84] appear to be based on the uncontrolled CO_2 emission rate from the engine specification sheet.[85] However, this fails to account for CO_2 created by the oxidation catalyst.[86] CO_2 emission resulting from catalytic oxidation must be included in the GHG emissions calculations.

6. ACHD should employ recommendations from EPA's Natural Gas STAR Program to reduce methane emissions from this facility.

EPA's Natural Gas STAR program is a voluntary program that encourages participating oil and natural gas companies to reduce methane emissions by implementing emission control technologies and best management practices.[87] These practices both reduce methane emissions and increase operational efficiency, often resulting in significant cost-savings for industry. Reducing methane emissions is essential because methane is over 20 times more potent a greenhouse gas than CO_2, and the oil and natural gas industry is the largest source of man-made methane emissions in the United States and the single largest source globally.[88] Most of the Gas STAR recommendations have the co-benefit of reducing VOC, and, in some cases, NOx

---

[81] AC-1 application, *supra* note 18 at 130.
[82] *Id*. at 147.
[83] *Id.* at 137-44.
[84] ACHD Permit Review Document, *supra* note 70 at 3.
[85] AC-1 application, *supra* note 18 at 130, 154.
[86] EPA, AP-42 Chapter 3.2 at 3.2-5.
[87] *See* EPA's Natural Gas STAR Program website, http://www.epa.gov/gasstar/basic-information/index.html#overview1; EPA, *What is Natural Gas STAR?* Fact Sheet, http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf.
[88] EPA, *What is Natural Gas STAR?* Fact Sheet, http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf.

emissions. ACHD must evaluate EPA Gas STAR methane reduction recommendations[89] for inclusion in the SAP facility permit, including but not limited to the measures discussed below.

A number of practices that do not seem to have been considered in the draft permit could be used to reduce emissions from compressor engine startup and shutdown. To reduce emissions during startup, the number of engine startups should be limited; additionally, maintaining engine ignitions to reduce the number of failed ignitions will prevent gas from being venting to the atmosphere as part of ignition.[90] To reduce emissions during shutdown, whenever possible the compressor engine should remain pressurized during shutdown, blowdown vent lines should be connected to the fuel gas system, and static seals should be employed to prevent rod packing leaks.[91]

Other practices that may be applicable to this facility can be used to address emissions from dehydrators and valves. SAP should use no-bleed pneumatic controllers to limit emission if the site has electricity available; if there is no electricity, low-bleed controllers should be required instead.[92] In general, SAP and ACHD should thoroughly review Gas STAR recommendations and identify those that can be applied to this facility and that will cost-effectively reduce methane emissions. These options should be incorporated into SAP's final permit.

7. The draft permit engine emission testing frequency is inadequate to ensure ongoing compliance with engine emission limits.

The draft permit for the SAP facility requires compressor engine emissions testing "at least once every 5 years."[93] This testing frequency is inadequate to ensure ongoing compliance with engine emission limits.

For instance, in 2008 the South Coast Air Quality Management District (SCAQMD) increased its stationary engine testing frequency to the earlier of every two years or 8,760 operating hours[94] and now requires weekly emissions checks with portable analyzers.[95] SCAQMD promulgated these tougher testing requirements after

[89] EPA Natural Gas STAR, *Recommended Technologies and Practices*, http://www.epa.gov/gasstar/tools/recommended.html.
[90] EPA Natural Gas STAR, *Reduce Natural Gas Venting with Fewer Compressor Engine Startups & Improved Engine Ignition*, http://www.epa.gov/gasstar/documents/reducethefrequencyofenginestarts.pdf.
[91] EPA Natural Gas STAR, *Reducing Emissions When Taking Compressors Off-Line*, http://www.epa.gov/gasstar/documents/ll_compressorsoffline.pdf.
[92] EPA Natural Gas STAR, *Recommended Technologies and Practices – Valves, available at* http://www.epa.gov/gasstar/tools/recommended.html#valves.
[93] ACHD, Superior Appalachian Pipeline, LLC Draft Installation Permit No. 0837-I001 (Feb. 3, 2012) condition V.A.2.b at 19 [hereinafter "AC-1 Draft Permit"].
[94] South Coast Air Quality Management District Compliance Guide to Rule 1110.2 Amendments (May 8, 2008) at 12-14, *available at*http://www.aqmd.gov/rules/doc/r1110-2/ComplianceGuide.pdf.
[95] *Id*. at 15-18.

unannounced stationary engine emission tests found that noncompliance with engine NOx and CO limits was common.[96]

NSPS subpart JJJJ requires large, uncertified engines to be tested "every 8,760 hours or 3 years, whichever comes first."[97] PADEP plan approvals routinely incorporate the NSPS subpart JJJJ emissions testing frequency for compressor engines, as well as an annual emissions test for NOx.[98] PADEP's general permit for natural gas production facilities also requires annual NOx emissions testing.[99]

8. SAP has failed to evaluate the impact of formaldehyde emissions on the ambient air.

ACHD cannot issue an installation permit unless the applicant has demonstrated that "[e]missions from the proposed source will not endanger the public health, safety or welfare."[100] The proposed facility has the potential to emit 7.05 TPY of formaldehyde,[101] a known human carcinogen. SAP must demonstrate emissions from the proposed facility will not result in ambient air concentrations of formaldehyde sufficient to endanger the public health, safety or welfare.

9. The draft installation permit's hourly PM emission limit for dehydrator/reboiler number 3 is incorrect.

The draft installation permit lists a 0.12 lb/hr particulate matter emission limit for dehydrator/reboiler number 3.[102] However, ACHD's technical review document lists a 0.012 lb/hr particulate matter (PM) limit.[103] The latter 0.012 lb/hr PM limit is consistent with Article XXI §2104.02.a.1.A's maximum PM emission rate of 0.008 lb/MMBtu:[104]

$$0.008 \text{ lb/MMBtu} * 1.5 \text{ MMBtu} = 0.012 \text{ lb/hr}$$

Thus ACHD must amend the installation permit to reflect the correct PM limit for dehydrator/reboiler number. 3 of 0.012 lb/hr.

---

[96] Craig McKim, Advances in NOx testing with Portable Analyzers (Jul. 9-10, 2008) at 11-15, *available at* http://www.icac.com/files/public/McKim.pdf.
[97] 40 CFR § 60.4243
[98] *See e.g.*, Attachment 8 - PADEP, Draft Plan Approval for EQT Callisto Compressor Station, Plan Approval No. 30-00194, condition C.II.a at 12.
[99] PADEP, General Permit 5 (Mar. 17, 2011) condition 16.b.ii at 8-9, *available at* http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/Final_GP-5_Amendments_Approved.pdf.
[100] Article XXI §2102.04.b.7.
[101] ACHD Permit Review Document, *supra* note 70 at 5.
[102] AC-1 Draft Permit *supra* note 94 at 26.
[103] ACHD Permit Review Document, *supra* note 70 at 7.
[104] *Id*. at 6.

10. Installation permit condition V.C.1.b's reference to the C.F.R. appears to be in error.

Draft installation permit condition V.C.1.b, which requires the use of a condenser on dehydrator #3, cites 40 C.F.R. § 60.42(c)(d). Section 60.42 is part of the NSPS for fossil-fuel-fired steam generators. Reference to this section appears to be in error.

Joe Osborne, Esq.
Legal Director
Group Against Smog & Pollution
5135 Penn Ave.
Pittsburgh, PA 15224
joe@gasp-pgh.org

Myron Arnowitt
Pennsylvania State Director
Clean Water Action
100 5th Ave
Pittsburgh, PA 15222
marnowitt@cleanwater.org

Joseph Otis Minott, Esq.
Executive Director
Clean Air Council
Suite 300
135 South 19th Street
Philadelphia, PA 19103
joe_minott@cleanair.org

Erika Staaf
Clean Water Advocate
PennEnvironment
1831 Murray Ave. Ste. 219
Pittsburgh, PA 15217
estaaf@pennenvironment.org