ROCKY MOUNTAIN CLEAN AIR ACTION

Clean Air For Healthy Children and Healthy Communities

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May 19, 2008

Claudia Smith
U.S. EPA Region 8
Air Program (8P-AR)
1595 Wynkoop Street
Denver, CO 80202

Re: Draft Title V Operating Permit for Florida River Compression Facility

Dear Ms. Smith:

Rocky Mountain Clean Air Action hereby submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA's") proposal to issue a Title V federal operating permit (hereafter "Title V permit") to BP America Production Company (hereafter "BP") for the operation of the Florida River Compression Facility. *See*, Draft Title V Permit No. V-SU-0022-05.00.

Rocky Mountain Clean Air Action is a Denver, Colorado-based, nonprofit membership group dedicated to protecting clean air in Colorado and the surrounding Rocky Mountain region for the health and sustainability of local communities. For the foregoing reasons, the EPA cannot issue the proposed Title V permit as proposed because it fails to ensure compliance with Prevention of Significant Deterioration ("PSD") and Title V requirements under the Clean Air Act ("CAA").

I. The Draft Title V Permit Fails to Ensure Compliance with Title V and PSD Requirements

A Title V Permit is required to include emission limitations and standards that assure compliance with all applicable requirements at the time of permit issuance. 42 USC § 7661c(a); 40 CFR § 71.6(a)(1). Applicable requirements include, among other things, PSD requirements set forth under Title I of the CAA and regulations at 40 CFR § 52.21. 40 CFR § 71.2. If a source will not be in compliance with an applicable requirement, including PSD, at the time of permit issuance, the applicant must disclose the violation and provide a narrative showing how it will come into compliance, and the permit must include a compliance schedule for bringing the source into compliance. 42 USC § 7661b(b); 40 CFR §§ 71.6(c)(3) and 71.5(c)(8).

The CAA prevents significant deterioration of air quality to protect human health and welfare and air quality in class I areas. 42 USC § 7470. Prevention of significant deterioration requirements apply to the construction of major sources and/or major modifications of major sources of air pollution in areas designated as attainment. 42 USC § 7475 and 40 CFR § 52.21(a)(2). In the case of BP's Florida River Compression Facility, the proposed Title V permit fails to assure compliance with PSD requirements under the CAA. Furthermore, the Title V permit fails to include compliance schedules to bring the sources into compliance with PSD requirements. As will be explained in more detail below, the EPA cannot issue the proposed permits as currently written.

A. The EPA Must Consider Emissions form Adjacent and Interrelated Pollutant Emitting Activities, including BP America's Coalbed Methane Wells and the Wolf Point Compressor Station to Assure PSD Compliance

The Florida River Compression Facility is currently a major source of air pollution due the fact that the facility has the potential to emit 250 tons/year or more of NOx. *See*, Statement of Basis for Draft Permit No. V-SU-0022-05.00 (hereafter "Statement of Basis") at 12. According to the Statement of Basis, "While this combined facility has never been required to receive a PSD permit to construct, significant emission increases due to modifications at the facility could trigger the PSD permitting requirements." *Id.* While the EPA claims that PSD review requirements have not yet been triggered for the Florida River Compression Faclity, this claim is baseless as **the EPA has not considered emissions from all interrelated pollutant emitting activities, namely BP's coalbed methane wells and the Wolf Point Compressor Station.**

Prevention of Significant Deterioration regulations at 40 CFR § 52.21(b)(5) define a stationary source as, "any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant." Regulations at 40 CFR § 52.21(b)(6) further define "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)[.]" The regulations further state, "Pollutant emitting activities are considered 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[.]"

The Florida River Compression Facility processes coalbed methane gas from BP's wells and the Wolf Point Compressor Station. *See*, Statement of Basis at 2. Before issuing the Title V permit for the Florida River Compression Facility, the EPA must consider and address pollutant emitting activities from these pollutant emitting activities which, as will be explained further, constitute adjacent and interrelated pollutant emitting activities under control by BP.

1. *BP's Coalbed Methane Wells*

BP is the largest coalbed methane producer in La Plata County in southwestern Colorado. As a recent Durango Herald new article reported "The lion's share of coal-bed methane gas production in La Plata County comes from one company: BP." *See*, Greenhill, J., "BP accounts for 55% of coal-bed gas production," *Durango Herald* (February 23, 2003), attached as **Exhibit 1**. Information from the Colorado Oil and Gas Conservation Commission ("COGCC") shows that BP owns and operates over 1,000 producing wells just in La Plata County. *See*, spreadsheet listing all of BP producing wells in La Plata County, attached as **Exhibit 2**. BP's coalbed methane wells are all pollutant emitting activities related to the production of coalbed methane in La Plata County. In fact, BP's coalbed methane wells appear to serve as support facilities to larger processing plants, such as the Florida River Compression Facility.

Indeed, information from the EPA, the Colorado Air Pollution Control Division, and other sources shows that activities related to coalbed methane wells release significant amounts of air pollution, particularly from compressor engines. *See*, Table 1. A recent report prepared for the Western Governors' Association shows that NOx and VOC emissions related to coalbed methane wells are released primarily from four main pollutant emitting activities at coalbed methane wells: 1) Compressor engines; 2) Heaters; 3) Dehydration; 4) Completion, flaring, and venting. *See*, Russell, J. and A. Pollack, "Oil and Gas Emission Inventories for the Western States," Final Report prepared for Western Governor's Association (December 27, 2005), attached as **Exhibit 3**. Compressor engines in coalbed methane producing regions, such as the San Juan Basin, are of particular concern in relation to NOx emissions. A more recent report prepared for the Western Governor's Association stated:

> In virgin or newly developed fields and basins the field pressures are sufficiently high that far fewer wellhead compressors are required to generate this [field] pressure than in mature fields and basins. The only exception to this general rule are basins with significant coal-bed methane (CBM) wells, which often have low gas pressures and require more wellhead compression; although even in these CBM fields and basins the usage of wellhead compression is generally no more than 5% of total wells.

See, Bar-Ilan, A., R. Friesen, A. Pollack, and A. Hoats, "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation, Phase II," Final Report Prepared for Western Governor's Association (September 2007), attached as **Exhibit 4**. Given the sheer number of wells operated and owned by BP, NOx and VOC emissions from the company's producing coalbed methane wells that supply the Florida River Compression Facility are most likely significant. Indeed, if 5% of total wells require wellhead compressors, then this would mean that over 50 compressor engines are associated with BP's more than 1,000 wells in La Plata County in southwestern Colorado.

Table 1. Sources of Air Pollution at Natural Gas Wells (*see*, Exhibit 3).

Pollutant Emitting Activity	Pollutants Released
Compressor engines	NOx
Heaters	NOx
Dehydration	NOx, VOCs
Completion, flaring, venting	NOx, VOCs

Not only are BP's producing coalbed methane wells pollutant emitting activities, but together with the Florida River Compression Facility, they are connected pollutant emitting activities under PSD and thus, a single source. As noted, BP operates more than 1,000 coalbed methane wells in La Plata County, all or some of which have a functional interrelationship with the Florida River Compression Facility. As the Statement of Basis for the Title V permit states, "The Florida River Compression Facility processes coal bed methane gas in order ot reduce CO_2 and water content to within pipeline specifications and compresses this gas for delivery into interstate pipelines." Statement of Basis at 2. Some or all of BP's coalbed methane wells clearly provide coalbed methane gas to the Florida River Compression Facility. Thus the facility depends upon the operations of these wells for its function. Similarly, all or some of the coalbed methane wells owned and operated by BP depend upon the Florida River Compression Facility for their operations. Without the existence of the Florida River Compression Facility, all or some of BP's coalbed methane wells would cease to operate as there would be no means of compressing, processing, and transporting natural gas to market pipelines.

Although information has not been presented by BP or by the EPA showing which of BP's producing natural gas wells supply coalbed methane gas to the Florida River Compression Facility, the available information from the COGCC shows that are dozens, perhaps hundreds, or more than a thousand, coalbed methane wells that are likely to supply the Florida River Compression Facility. As already explained, BP owns and operates over 1,000 producing coalbed methane wells located in La Plata County, which is where the Florida River Compression Facility is also located. According to data from the COGCC, a number of these wells are located not more than a mile away from the Florida River Compression Facility. At least four coalbed methane wells are located in Section 25 of Township 34 N, Range 9 West. *See*, Exhibit 2 at 83.[1] A number of others are located within two miles of the Florida River Compression Facility, including four wells in Section 24, T34N, R9W, six wells in Section 23, T34N, R9W, five wells in Section 26, T34N, R9W, four wells in Section 36, T34N, R9W, among many others. *See*, Exhibit 2 at 81-84. The best information we have available to us shows that there are hundreds, if not more than 1,000, coalbed methane wells in close proximity to the Florida River Compression Facility, and that most, if not all, of these wells, or pollutant emitting activities, are interrelated with the Florida River Compression Facility n in that they support operations of the Compression Facility.

Additionally, BP's natural gas wells are part of the same major industrial grouping as the Florida River Compression Facility. According to the Standard Industrial Classification Manual, producing natural gas wells fall under Major Group 13, or "Oil and Gas Extraction."[2] The draft Title V permit for the Florida River Compression Facility identifies the facility as falling under SIC "1311." Draft Title V permit at 7.

Finally, BP's natural gas wells are considered adjacent for PSD purposes. These pollutant emitting activities are located entirely within La Plata County, Colorado. Although the EPA has noted that the distance associated with "adjacent" "must be considered on a case-by-

[1] These coalbed methane wells have API identification numbers of 05-067-08728, 05-067-07421, 05-067-06816, and 05-067-08377.

[2] *See*, http://www.osha.gov/oshstats/sicser.html.

case basis," the agency has noted that two pollutant emitting activities that are interdependent operations under common control can be considered adjacent when they are upwards of 20 miles apart or even greater. *See*, Memo from Richard R. Long, Region VIII Dir., Air and Radiation Program to Lynn Menlove, Manager, New Source Review Section, Utah Division of Air Quality (May 21, 1998), attached as **Exhibit 5**. EPA noted that in relation to two interdependent facilities in Utah 21.5 miles apart that, "the lengthy distance between the facilities 'is not an overriding factor that would prevent them from being considered a single source.'" *Id.* at 2. The fact that BP's producing coalbed methane wells are all located primarily within La Plata County strongly indicates these pollutant emitting activities are adjacent to the Florida River Compression Facility for PSD purposes. At the least, the best available information shows that there are many wells less than 21.5 miles away from the Florida River Compression Facility.

Together with the Florida River Compression Facility, the coalbed methane wells that supply the Facility with natural gas comprise a single source under PSD. The natural gas wells are pollutant emitting activities, are adjacent to the Florida River Compression Facility, are interrelated with the Florida River Compression Facility, belong to the same major industrial grouping, and are under common control or ownership by BP. Under the CAA, the Florida River Compression Facility and the coalbed methane wells that supply the Facility must be aggregated together and considered a single source to assure compliance with PSD in order for the Title V permit to be legally valid.

2. *BP's Wolf Point Compressor Station*

In addition to BP's producing coalbed methane wells, BP's Wolf Point Compressor Station also must be considered a single source under PSD to ensure compliance with Title V and PSD requirements.

According to the draft Title V permit for the Wolf Point Compressor Station, the Compressor Station directly provides coalbed methane gas to the Florida River Compression Facility. The draft Title V permit states:

> Upon entering the compressor station, the gas first passes through an inlet separator vessel to remove any free liquids in the gas stream by gravity. The gas then passes to a filter vessel, which serves to filter out any solids such as coal dust in the gas. The gas is then compressed and finally passes through an outlet coalescer vessel which removes any entrained droplets of lubricating oil before being metered and sent to the BP Florida River Compressor Facility for further processing.

Draft Title V Permit for the Wolf Point Compressor Station, Permit Number V-SU-0034-07.00, attached as **Exhibit 6**. Thus, it appears that there is no question that the Wolf Point Compressor Station is interrelated and adjacent to the Florida River Compression Facility. Indeed, the Wolf Point Compressor Station directly supports operations at the Florida River Compression Facility, providing pretreated coalbed methane gas for further processing.

There is also no question that the Wolf Point Compressor Station is a pollutant emitting activity. As the Draft Statement of Basis for the Draft Wolf Point Compressor Station Title V permit discloses, the facility has a potential to emit 83.26 tons of NOx, 180.14 tons of carbon monoxide, 54.45 tons of VOCs, among other pollutants, on an annual basis. *See*, Draft Statement of Basis for Permit No. V-SU-0034-07.00, attached as **Exhibit 7**.

Additionally, the Wolf Point Compressor Station is a part of the same major industrial grouping as the Florida River Compression Facility. According to the Draft Title V permit for the Wolf Point Compressor Station, the facility falls under Standard Industrial Classification Code "1311." Exhibit 6 at 1. The Wolf Point Compressor Station therefore has the same SIC code as the Florida River Compression Facility.

Together with the Florida River Compression Facility, the Wolf Point Compressor Station, which supplies the Florida River Compression Facility with natural gas, comprise a single source under PSD. The Wolf Point Compressor Station is a pollutant emitting activity, it is adjacent to the Florida River Compression Facility, is clearly interrelated with the Florida River Compression Facility, belongs to the same major industrial grouping, and is under common control or ownership by BP. Under the CAA, the Florida River Compression Facility and the Wolf Point Compressor Station must be aggregated together and considered a single source to assure compliance with PSD in order for the Title V permit to be legally valid.

B. The EPA Must Consider Emissions form Adjacent and Interrelated Pollutant Emitting Activities, including BP America's Coalbed Methane Wells and the Wolf Point Compressor Station to Assure Title V Compliance

The failure of the EPA to consider and address emissions from interrelated and adjacent BP coalbed methane wells and the Wolf Point Compressor Station, which all supply coalbed methane gas to the Florida River Compression Facility, further renders the draft Title V permit to be in violation of Title V regulations at 40 CFR § 71.

Title V regulations at 40 CFR § 71 explicitly require all adjacent pollutant emitting activities under common control and belonging to a single major industrial grouping be considered as a single source for Title V permitting purposes. In fact, the definition of a "major source" under 40 CFR § 71.2 mirrors the definition of a "major source" found at 40 CFR § 52.21.

In relation to oil and gas developments, such as the Florida River Compression Facility and the coalbed methane wells and compressor stations that supply the Facility, the EPA has explicitly stated that oil and gas pollutant emitting activities cannot be piecemealed in relation to Title V permitting of major sources. In its proposed interim approval of the state of Oklahoma's operating permit program, the EPA stated, "Nonaggregation of oil and gas units is provided only for the emission of hazardous air pollutants in the Federal rule. 40 CFR 70.2 requires **all sources located on contiguous or adjacent properties, under common control, and belonging to a single major industrial grouping to be considered as the same source**." 60 Fed. Reg. 13088-13095 (emphasis added).

The EPA itself has held that natural gas compressor stations and their associated wells must be considered together as a single source for Title V purposes. In a 1999 memo, the EPA stated:

In the Code of Federal Regulations at 40 CFR 71.2 the definition of "major source" states, in part:

> 'Major source means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping.....'

We interpret this to mean that each compressor station with its associated emitting units (e.g. compressor engines, wells, pumps, dehydrators, storage and transmission tanks, etc...) comprises a 'group of stationary sources' and would be considered a single source for purposes of determining Title V applicability.

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Jack Vaughn, EnerVest San Juan Operating Co. (July 8, 1999), attached as **Exhibit 8**. The EPA's position is clearly applicable in the case of the Florida River Compression Facility, meaning the EPA is required to issue a Title V permit for the Compression Facility together with BP's coalbed methane wells and the Wolf Point Compressor Station as a single source to ensure compliance with 40 CFR § 71.6.

II. The EPA Cannot Rely on the 2007 Wehrum Memo When Permitting the Florida River Compression Facility

We understand the EPA may be inclined to rely on a flawed policy guidance memo issued by former political appointee and EPA Assistant Administrator, William L. Wehrum (hereafter "Wehrum memo") when permitting the Florida River Compression Facility. This memo claims to provide guidance for determining if and how to aggregate pollutant emitting activities related to oil and gas operations under New Source Review ("NSR") and Title V permitting programs. We respectfully submit that this guidance memo inappropriately subverts the plain language of federal NSR and Title V regulations and that it would be inappropriate for the EPA to rely on this memo. What's more, the memo was illegally promulgated without prior rulemaking, in violation of the Administrative Procedures Act ("APA").

1. The Wehrum Memo is Substanively Flawed

Indeed, the Wehrum memo suffers from two major flaws. To begin with, it inappropriately conflates Section 112 of the Clean Air Act, which addresses the regulation of hazardous air pollutants, with the NSR and Title V permitting programs, which are set forth under Sections 160, et seq., and 501, et seq., of the Clean Air Act, respectively. Section 112(n)(4)(A) contains a specific provision that prohibits aggregating interrelated oil and gas facilities when assessing whether a facility is a major source of hazardous air pollutants. In his memo, Wehrum advises permitting authorities, such as the EPA, to "look to the Section 112 approach of segregating" oil and gas operations under the NSR and Title V permitting programs. Wehrum Memo at 4. While Wehrum's advice is well and good for decisions made under

Section 112, it is ill-advice for permitting authorities carrying out the NSR and Title V permitting programs.

Secondly, the Wehrum memo defies nearly three decades of EPA policy and guidance making clear that the determination of whether to aggregate pollutant emitting activities is largely dependent upon the "common sense" notion of a source. This "notion," first enumerated by the EPA in its 1980 regulations implementing the Prevention of Significant Deterioration ("PSD") program (42 Fed. Reg. 52695), means that two or more facilities with a functional interrelationship, such as a support facility to a larger plant or factory, should be considered together a single source of air pollution for NSR and Title V permitting purposes—irrespective of the distance between the facilities.

The Wehrum memo implicitly rejects this long-held means of assessing whether or not to aggregate pollutant emitting activities under NSR and Title V. Indeed, Wehrum does not even address whether two or more oil and gas operations may have a functional interrelationship, but rather simply asserts that the concept of "proximity," or the "physical distance between two activities," should be the sole factor in determining whether to aggregate. Wehrum goes on to assert that permitting authorities should only aggregate two or more oil and gas operations "if they are physically adjacent, or if they are separated by no more than a short distance (e.g. across a highway, separated by a city block or some similar distance)." Wehrum Memo at 4.

While the EPA has recognized that distance between two or more facilities may be a factor in determining whether or not to aggregate pollutant emitting activities, the agency has never taken the position that distance should be the sole determining factor. For example, in response to a request for guidance from the State of Utah, EPA Region 8 stated:

> [A]ny evaluation of what is "adjacent" must relate to the guiding principle of a common sense notion of "source." (The phrase "common sense notion" appears on page 52695 of the August 7, 1980 PSD preamble, with regard to how to define "source.") Hence, a determination of "adjacent" should include an evaluation of whether the distance between two facilities is sufficiently small that it enables them to operate as a single "source."

Exhibit 5 at 2.[3] The EPA has long held that "the distance associated with 'adjacent' must be considered on a case-by-case basis." *Id.* at 1.[4] This was firmly noted in the preamble to the

[3] *See also*:

Letter from Richard R. Long, Region VIII Director, Air Program, to Lynn R. Menlove, Manager, New Source Review Section, Division of Air Quality, Utah Department of Environmental Quality (August 8, 1997) (stating, "To our general knowledge, previous determinations, which have been made by EPA and states, have always determined that activities which support the primary activities of a source are considered to be part of the sources to which they provide support. Distance between the operations is not nearly as important in determining if the operations are part of the same source as the possible support that one operation provides for another."), attached as **Exhibit 9.**

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Jeffrey L. Ingerson, Senior Environmental Specialist, Questar Gas Management Company (August 7, 1998) (stating, "Distance between operations is not nearly as important in determining if the operations are part of the same source as the possible support that one operation provides for another."), attached as **Exhibit 10.**

agency's 1980 PSD regulations, which state 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." 42 Fed. Reg. 52676.

Despite the EPA's long held position, the Wehrum memo not only asserts that permitting authorities should only assess distance in determining whether to aggregate oil and gas operations as single sources, but clearly directs permitting authorities to reject considering adjacency on a "case-by-case" basis in relation to oil and gas operations. Indeed, the Wehrum memo specifically directs permitting authorities to consider "adjacency" of oil and gas operations only in relation to proximity. Amazingly, the Wehrum memo does exactly what EPA has long held it could not do: say "precisely" how far apart activities must be in order to be treated as separate sources under NSR.

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Dennis Myers, Construction Permit Unit Leader, Stationary Sources Program, Air Pollution Control Division, Colorado Department of Public Health and Environment (April 20, 1999) (stating, "whether two facilities are 'adjacent' is based on the 'common sense' notion of a sources and the functional interrelationship of the facilities, and is not simply a matter of the physical distance between two facilities."), attached as **Exhibit 11**.

[4] *See also*:

Memo from Steven Rothblatt, Region V Chief, Air Programs Branch to Edward E. Reich, Director, Stationary Source Enforcement Division (June 8, 1981) (stating that EPA adjacency determinations are based on a case-by-case basis), attached as **Exhibit 12**.

Memo from William B. Hathaway, Region VI Director, Air, Pesticides and Toxics Division to Allen Eli Bell, Executive Director, Texas Air Control Board (November 3, 1986) (stating "For cases where sources are not located on contiguous or adjacent properties, EPA cannot say precisely how far apart the activities must be in order to be treated separately. EPA can only answer that question through case-by-case determinations[.]", attached as **Exhibit 13**.

Memo from Robert G. Kellam, OAQPS Acting Director, Information Transfer and Program Integration to Richard R. Long, Region VIII Director, Air Program (August 27, 1996) (stating "Whether facilities are contiguous or adjacent is determined on a case-by-case basis, based on the relationship between the facilities."), attached as **Exhibit 14**.

Letter from Joan Cabreza, Region X Permits Team Leader, Office of Air Quality to Andy Ginsberg, Manager, Program Operations Section, Air Quality Division, Oregon Department of Environmental Quality (August 7, 1997) (stating, "The guiding principle behind this guidance is the common sense notion of plant. That is, pollutant emitting activities that comprise or support the primary product or activity of a company or operation must be considered part of the same stationary source."), attached as **Exhibit 15**.

Letter from Steven C. Riva, Region II Chief, Permitting Section, Air Programs Branch to John T. Higgins, Director, Bureau of Application Review and Permitting, Division of Air Resources, New York State Department of Environmental Conservation (October 11, 2000) (stating "there is no bright line, numerical standard for determining how far apart activities may be and still be considered 'contiguous' or 'adjacent.' As explained in the preamble to the August 7, 1980 PSD rules, such a decision must be made on a case-by-case basis."), attached as **Exhibit 16**.

It is true that the EPA is free to change its policy positions, but the agency must at least articulate a rationale, particularly when, as in this case, the policy represents a 180 degree shift in position. In the case of the Wehrum memo, the only reason given for rejecting nearly 30 years of consistent EPA policy is "the diverse nature of oil and gas activities." Wehrum Memo at 3. The only piece of information that the Wehrum memo cites to support this rationale is the fact that Section 112 of the Clean Air Act prohibits aggregating interrelated oil and gas facilities when assessing whether a facility is a major source of hazardous air pollutants. Once again, it is inappropriate to assume that since Congress clearly specified exemptions under Section 112 that Congress intended similar exemptions to apply under other programs of the Clean Air Act. Furthermore, it is inappropriate to assume that since Congress recognized the oil and gas industry was unique in the context of Section 112 hazardous air pollutant regulation requirements, Congress similarly recognized the oil and gas industry was unique in the context of NSR and Title V regulatory requirements.

Notwithstanding the claimed "diverse" nature of oil and gas activities, it has never prevented the EPA from determining that oil and gas operations should be aggregated under the NSR and Title V permitting programs, notwithstanding the fact that such operations were not in close proximity to each other. For example, in a 1999 memo, the EPA concluded that:

> [E]ach compressor station with its associated emitting units (e.g. compressor engines, wells, pumps, dehydrators, storage and transmission tanks, etc...) comprises a 'group of stationary sources' and would be considered a single source for purposes of determining Title V applicability.

Exhibit 8.[5] In these situations, the EPA has made clear that, while distance is a consideration, the interrelatedness of pollutant emitting activities is key to determining whether to aggregate oil and gas operations. As the EPA has further directed, natural gas compressor stations and their associated emitting units, including wells, should be aggregated as a single source.[6]

Notably, the EPA has issued these directives related to the aggregation of oil and gas operations under the NSR and Title V permitting programs notwithstanding the claimed "diverse" nature of the activities. Why is this? Because the statutory provisions of the Clean Air Act make clear that under the NSR and Title V permitting apply equally to all industry sectors and make no exceptions for oil and gas.[7]

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[5] *See also*:

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program to Lee Ann Elsom, Environmental Coordinator, Citation Oil and Gas Corporation (December 9, 1999), attached as **Exhibit 17.**

[6] Although the referenced EPA memos address permitting under Title V of the Clean Air Act, the direction is equally applicable to NSR permitting requirements given that the definition of "major source" under both Title V and NSR regulations are exactly the same.

[7] Under the Clean Air Act, the definition of "major stationary source" includes "any stationary facility or source of air pollutants which directly emits, or has the potential to emit, one hundred tons per year or more of any air pollutant" except as otherwise "expressly provided" by the Act. Because the Clean Air Act does not expressly provide an exemption to oil and gas operations under Title V and NSR permitting requirements, regulations addressing both Title V and NSR permitting requirements must apply to oil and gas operations as equally as any other industrial sector.

At the least, the EPA has made clear that it is incumbent upon permitting authorities to understand the full nature of oil and gas operations and their potentially interrelated pollutant emitting activities before issuing Title V and/or NSR permits. In a 2004 letter to the Colorado Air Pollution Control Division related to permitting of a natural gas processing plant, the EPA recommended that:

> [A]n analysis of how natural gas is transported to and from the Rifle [natural gas processing] Station should be conducted. The role the Rifle Station plays in the final product of any natural gas facility or facilities providing this compression should be established. Once this information is obtained, a factual and legal analysis should be conducted to determine if the Rifle Station is operating independently, or whether it should be considered a single stationary source with other pollutant emitting activities.

Letter from Callie A. Videtich, Region VIII Leader, Air Technical Assistance Unit, to Roland Hea, Unit Leader, Construction Permit Program, Air Pollution Control Division, Department of Public Health and Environment (October 18, 2004), attached as **Exhibit 18**. The EPA continued, "[W]e recommend that the Division completely analyze whether the Rifle [natural gas processing] Station is truly operating independently as a single stationary source before establishing synthetic minor limits for the Title V program." *Id.*

Accordingly, as the EPA moves to analyze whether or not to aggregate interrelated pollutant emitting activities with the Florida River Compression Facility, the agency must engage in a thorough and in-depth assessment that does not simply rely on the Wehrum memo, but addresses the extent to which the Florida River compression Facility is operating independently. The EPA must conduct a factual and legal analysis that assesses whether coalbed methane wells and the Wolf Point Compressor Station are connected to the Florida River Compression Facility by pipelines are interrelated pollutant emitting activities that should be aggregated with the Compression Facility as a single source.

2. *The Wehrum Memo is Procedurally Flawed*

Procedurally, the Wehrum memo is flawed because it has not followed proper rulemaking procedures in accordance with the APA, 5 USC § 553. As noted earlier in these comments, the Wehrum memo is substantive in nature in that it changes nearly 30 years of established EPA policy. Furthermore, although the Wehrum memo claims to provide only "guidance," to permitting authorities, the guidance is in fact substantive direction that permitting authorities are now forced to adhere by. The memo is much more than a general statement of policy, but rather establishes a new regulatory definition that dramatically changes the administration of NSR and Title V permitting programs. Finally, the memo itself is substantive in nature in that it does not provide clarification with regards to an existing statutory or regulatory definition, but rather provides a new definition of what constitutes a major source under NSR and Title V.

Before the Wehrum memo can have any semblance of validity, it must be subject to public notice and comment requirements under 5 USC § 553. The EPA therefore cannot rely on the memo to respond to our comments unless and until it has been subject to proper rulemaking procedures under the APA.

Thank you for the opportunity to comment. Please keep us apprised of any future actions related to the Draft Title V permit for BP's Florida River Compression Facility. Thank you.

Sincerely,

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TABLE OF EXHIBITS

1. Greenhill, J., "BP accounts for 55% of coal-bed gas production," *Durango Herald* (February 23, 2003);

2. Spreadsheet listing all of BP producing wells in La Plata County;

3. Russell, J. and A. Pollack, "Oil and Gas Emission Inventories for the Western States," Final Report prepared for Western Governor's Association (December 27, 2005);

4. Bar-Ilan, A., R. Friesen, A. Pollack, and A. Hoats, "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation, Phase II," Final Report Prepared for Western Governor's Association (September 2007);

5. Memo from Richard R. Long, Region VIII Dir., Air and Radiation Program to Lynn Menlove, Manager, New Source Review Section, Utah Division of Air Quality (May 21, 1998);

6. Draft Title V Permit for the Wolf Point Compressor Station, Permit Number V-SU-0034-07.00;

7. Draft Statement of Basis for Permit No. V-SU-0034-07.00;

8. Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Jack Vaughn, EnerVest San Juan Operating Co. (July 8, 1999);

9. Letter from Richard R. Long, Region VIII Director, Air Program, to Lynn R. Menlove, Manager, New Source Review Section, Division of Air Quality, Utah Department of Environmental Quality (August 8, 1997);

10. Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Jeffrey L. Ingerson, Senior Environmental Specialist, Questar Gas Management Company (August 7, 1998);

11. Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Dennis Myers, Construction Permit Unit Leader, Stationary Sources Program, Air Pollution Control Division, Colorado Department of Public Health and Environment (April 20, 1999);

12. Memo from Steven Rothblatt, Region V Chief, Air Programs Branch to Edward E. Reich, Director, Stationary Source Enforcement Division (June 8, 1981);

13. Memo from William B. Hathaway, Region VI Director, Air, Pesticides and Toxics Division to Allen Eli Bell, Executive Director, Texas Air Control Board (November 3, 1986);

14. Memo from Robert G. Kellam, OAQPS Acting Director, Information Transfer and Program Integration to Richard R. Long, Region VIII Director, Air Program (August 27, 1996);

15. Letter from Joan Cabreza, Region X Permits Team Leader, Office of Air Quality to Andy Ginsberg, Manager, Program Operations Section, Air Quality Division, Oregon Department of Environmental Quality (August 7, 1997);

16. Letter from Steven C. Riva, Region II Chief, Permitting Section, Air Programs Branch to John T. Higgins, Director, Bureau of Application Review and Permitting, Division of Air Resources, New York State Department of Environmental Conservation (October 11, 2000);

17. Letter from Richard R. Long, Region VIII Director, Air and Radiation Program to Lee Ann Elsom, Environmental Coordinator, Citation Oil and Gas Corporation (December 9, 1999);

18. Letter from Callie A. Videtich, Region VIII Leader, Air Technical Assistance Unit, to Roland Hea, Unit Leader, Construction Permit Program, Air Pollution Control Division, Department of Public Health and Environment (October 18, 2004).

EXHIBIT 1

Greenhill, J., "BP accounts for 55% of coal-bed gas production," *Durango Herald* (February 23, 2003).

BP accounts for 55% of coal-bed gas production

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February 23, 2003

By Jim Greenhill
Herald Staff Writer


NANCY RICHMOND / Herald
Craig Marcum, BP production foreman, at the Sossoman Gas Unit No. 1. Brook Jobes, a BP lift specialist, suggested student involvement in decorating the gas well next to Bayfield High School. Art students held a contest to decorate the well to reflect school spirit.


NANCY RICHMOND / Herald
A worker walks past equipment at BP's Florida River Facility, where coal-bed methane gas from La Plata County wells gets its final cleaning and is delivered to customers through one of three national pipelines.

The lion's share of coal-bed methane gas production in La Plata County comes from one company: BP.

Although BP controls only about 900 of the county's 2,200 producing gas wells, the company accounts for 55 percent of the county's coal-bed methane gas production, with the Southern Ute Indian Tribe's Red Willow a distant second, according to BP statistics.

The company also is the largest net gas producer in the San Juan Basin, which covers both La Plata County gas fields and those across the border in San Juan County, N.M.

"Our production in La Plata County right here in this office amounts to 20 percent of BP's North American hydrocarbon production, so it's a significant business," said Jeff Spitler, Durango operations manager.

The company has been in the San Juan Basin since the 1940s, when it was called Amoco. A series of mergers and acquisitions resulted in the company now known as BP America Production Co. The company's San Juan Basin interests include the old Amoco, Tenneco and Vastar operations.

BP's San Juan Performance Unit employs 125 people in Durango, 100 in Farmington and 80 supporting employees in the parent company's Houston, Texas, office. The company operates 3,175 gas wells across the San Juan Basin and owns an interest in an additional 2,250 wells operated by other producers. BP works with 40 owners who have working interests in San Juan Basin gas wells and 30,000 royalty owners.

The 125 Durango employees share a $7.3 million payroll, and the company provides work for

NANCY RICHMOND / Herald

Dave Knibbs, BP water team leader, shows equipment at the company's Los Pinos Disposal Facility that enables BP to monitor its operations from one location in southeast La Plata County. If they need to, operators can shut down any of the company's equipment in La Plata County with the click of a mouse.

NANCY RICHMOND / Herald

Jeff Spitler, BP's Durango operations manager, stands near the cooling fan for one of the four gas-fired compressors at the Dry Creek Compressor Station. The V12 engines produce 1,200 horsepower each, and are used to increase gas pipeline pressure from 50 pounds to 350 pounds and remove some water from gas piped in from about 100 surrounding wells.

payroll, and the company provides work for between 100 and 300 contract employees, depending on what operations it is conducting.

"We produce about 675 million cubic feet of gas a day (in La Plata County)," Spitler said. "Our daily gas production exceeds the fuel consumption of the state of South Carolina."

BP is two years into a program to drill infill gas wells allowed when the Colorado Oil and Gas Conservation Commission said gas wells in designated areas of La Plata County could be drilled every 160 acres instead of every 320 acres. The company expects to drill 380 new wells in a five or six year period; it has completed 130 so far.

What BP gets from a well is a mixture of coal-bed methane gas and water. The mixture is separated at the well head, and the water is either piped or trucked to reinjection sites where BP pumps it back into the ground 7,000 to 8,000 feet below the surface.

"We're required to inject (produced water)," said David Knibbs, BP water team leader. An exception was made in the Missionary Ridge Fire, when BP was given a permit that allowed it to donate produced water for firefighting efforts.

Gas produced from a well is sent by pipeline to a compressor station, such as the one at Dry Creek, near Bayfield, where gas is gathered from some 100 wells, more water removed and pipeline pressure raised from 50 pounds to 350 pounds by heavily soundproofed massive gas-fired compressors.

From a compressor station, the gas is piped to BP's Florida River Facility in southeast La Plata County.

The Florida River plant removes even more water and carbon dioxide and increases pipeline pressure to up to 800 pounds per square inch. The gas is delivered to buyers through the El Paso Natural Gas, Northwest or TransWestern pipelines. Most of it goes to power California electrical generating plants, not for local use.

BP and other gas producing companies are not always popular with coal-bed methane production opponents.

But company representatives say BP puts a high priority on the environment and has been making strides in improving gas production techniques.

One example: The Everett Jones No. 1 and No. 2 wells in the Meadows subdivision on Florida Mesa.

Instead of drilling a second well on a new well pad, BP used directional drilling – drilling at an angle instead of straight down – to enable the company to add a new well at an existing pad.

The company also made the well equipment low profile, painted equipment in so-called camouflage colors – Sherwin Williams calls the colors BP environmental green and BP environmental brown – and runs the equipment with quiet electric engines.

The well pad is surrounded with a berm and trees to further reduce the visual impact.

Reach Staff Writer Jim Greenhill at jim@durangoherald.com

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EXHIBIT 2

spreadsheet listing all of BP producing wells in La Plata County

BP Oil and Gas Wells in La Plata County (Data from COGCC)

Facility Type	Facility ID/ API	Facility Name/ Number	Operator Name/ Number	Status	Field Name/ Number	Location
WELL	05-067-06327	BONDS GAS UNIT 1 E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 1 32N 10W
WELL	05-067-05787	BONDS GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 1 32N 10W
WELL	05-067-06667	BONDS GAS UNIT 3 E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 1 32N 10W
WELL	05-067-06678	BONDS GAS UNIT 2 E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 1 32N 10W
WELL	05-067-07008	SOUTHERN UTE 2-Mar	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 2 32N 10W
WELL	05-067-07492	SOUTHERN UTE 32-10 1-Mar	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 3 32N 10W
WELL	05-067-07509	SOUTHERN UTE 32-10 3-Apr	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 4 32N 10W
WELL	05-067-07111	SOUTHERN UTE 32-10 2-Apr	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 4 32N 10W
WELL	05-067-07596	SOUTHERN UTE TRIBAL XX PLA-9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 5 32N 10W
WELL	05-067-07597	SOUTHERN UTE TRIBAL UU PLA-9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 6 32N 10W

WELL	05-067-07835	SOUTHERN UTE TRIBAL J 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 7 32N 10W
WELL	05-067-07182	SOUTHERN UTE TRIBAL KK 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 7 32N 10W
WELL	05-067-07235	SOUTHERN UTE TRIBAL MM 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 8 32N 10W
WELL	05-067-07183	SOUTHERN UTE TRIBAL LL 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 8 32N 10W
WELL	05-067-07112	SOUTHERN UTE 32-10 2-Sep	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 9 32N 10W
WELL	05-067-07116	SOUTHERN UTE 32-10 1-Sep	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 9 32N 10W
WELL	05-067-07617	SOUTHERN UTE 32-10 3-Oct	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 10 32N 10W
WELL	05-067-07521	M. H. MONTGOMERY GU A PLA-9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 12 32N 10W
WELL	05-067-06277	SOUTHERN UTE 1-12 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 12 32N 10W
WELL	05-067-06752	SOUTHERN UTE 1-12 GAS UNIT 3-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 12 32N 10W
WELL	05-067-06758	SOUTHERN UTE 1-12 GAS UNIT 1-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 12 32N 10W
WELL	05-067-07118	SOUTHERN UTE 32-10 14-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 14 32N 10W

WELL	05-067-07117	SOUTHERN UTE 32-10 14-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 14 32N 10W
WELL	05-067-07342	SOUTHERN UTE 32-10 15-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 15 32N 10W
WELL	05-067-07119	SOUTHERN UTE 32-10 15-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 15 32N 10W
WELL	05-067-07343	SOUTHERN UTE 32-10 16-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 16 32N 10W
WELL	05-067-07295	SOUTHERN UTE 32-10 16-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 16 32N 10W
WELL	05-067-07568	SOUTHERN UTE TRIBAL I PLA 9 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 17 32N 10W
WELL	05-067-07184	SOUTHERN UTE GAS UNIT NN 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 17 32N 10W
WELL	05-067-07244	SOUTHERN UTE TRIBAL OO PLA 9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 18 32N 10W
WELL	05-067-07795	SOUTHERN UTE TRIBAL H 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 18 32N 10W
WELL	05-067-07428	CLARK CUMMINS GAS UNIT PLA 9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 19 32N 10W
WELL	05-067-07399	HENDRICKSON GAS UNIT A PLA 9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 20 32N 10W

WELL	05-067-07409	HENDRICKSON GAS UNIT B PLA 9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 20 32N 10W
WELL	05-067-07598	SOUTHERN UTE TRIBAL SS 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 21 32N 10W
WELL	05-067-07587	JB GARDNER GAS UNIT A PLA 9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 22 32N 10W
WELL	05-067-07588	ROBIN FRAZIER GAS UNIT PLA 9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 23 32N 10W
WELL	05-067-07620	BROWN 32-6-3 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 3 32N 6W
WELL	05-067-08779	BROWN GAS UNIT 32-6-3 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 3 32N 6W
WELL	05-067-05144	H C MCDONALD ET AL 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 7 32N 6W
WELL	05-067-06663	PAYNE 8-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 8 32N 6W
WELL	05-067-08955	TUBBS GAS UNIT 32-6-9 B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 9 32N 6W
WELL	05-067-07632	TUBBS 32-6-9 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 9 32N 6W
WELL	05-067-07517	TUBBS 32-6-9 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 9 32N 6W

WELL	05-067-07621	BROWN 32-6-10 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 10 32N 6W
WELL	05-067-07601	BAKER GAS UNIT32-6-10 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 10 32N 6W
WELL	05-067-08868	BROWN 32-6-10 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 10 32N 6W
WELL	05-067-07544	MCKEEN 32-6-15 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 15 32N 6W
WELL	05-067-07515	SUTTON 32-6-16 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 16 32N 6W
WELL	05-067-07516	ESPINOSA 32-6-16 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 16 32N 6W
WELL	05-067-07530	LOPEZ 32-6-18 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 18 32N 6W
WELL	05-067-07529	OLGUIN 32-6-18 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 18 32N 6W
WELL	05-067-09091	SCHOFIELD GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 3 32N 7W
WELL	05-067-07859	SCHOFIELD GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 3 32N 7W
WELL	05-067-06295	SNOOK GAS UNIT B 1A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 5 32N 7W
WELL	05-067-07857	SNOOK GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 5 32N 7W

WELL	05-067-05157	SNOOK GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 5 32N 7W
WELL	05-067-05154	SOUTHERN UTE 32-7 1-Jun	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 6 32N 7W
WELL	05-067-06206	SOUTHERN UTE 32-7 2-Jun	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 6 32N 7W
WELL	05-067-05139	SNOOKS GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 7 32N 7W
WELL	05-067-07843	SNOOK GAS UNIT C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 7 32N 7W
WELL	05-067-06293	SNOOK GAS UNIT A 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 7 32N 7W
WELL	05-067-05120	SOUTHERN UTE 32-7 1-Jul	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 7 32N 7W
WELL	05-067-08291	SOUTHERN UTE 32-7 4-Jul	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 7 32N 7W
WELL	05-067-06340	WIRT GAS UNIT D 2M	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 8 32N 7W
WELL	05-067-05115	WIRT GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 8 32N 7W
WELL	05-067-07838	DAVIES GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 8 32N 7W
WELL	05-067-06326	WIRT GAS UNIT D 1-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 8 32N 7W

WELL	05-067-06302	WIRT GAS UNIT D 3M	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 8 32N 7W
WELL	05-067-08729	WIRT GAS UNIT F 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 8 32N 7W
WELL	05-067-07868	WIRT GAS UNIT F 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 8 32N 7W
WELL	05-067-05131	WIRT GAS UNIT E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 8 32N 7W
WELL	05-067-06314	KNIGHT GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 17 32N 7W
WELL	05-067-08745	KNIGHT GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 17 32N 7W
WELL	05-067-07867	KNIGHT GAS UNIT C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 17 32N 7W
WELL	05-067-07842	KNIGHT GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 17 32N 7W
WELL	05-067-05076	KNIGHT GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 17 32N 7W
WELL	05-067-06325	KNIGHT GAS UNIT D 2M	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 17 32N 7W
WELL	05-067-07102	SOUTHERN UTE 32-7 18-7	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 18 32N 7W
WELL	05-067-06194	SOUTHERN UTE 32-7 18-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 18 32N 7W

WELL	05-067-08238	SOUTHERN UTE 32-7 18-8	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 18 32N 7W
WELL	05-067-05058	SOUTHERN UTE 32-7 18-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 18 32N 7W
WELL	05-067-07101	SOUTHERN UTE 32-7 18-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 18 32N 7W
WELL	05-067-06208	SOUTHERN UTE 32-7 18-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 18 32N 7W
WELL	05-067-08251	SOUTHERN UTE 32-7 18-9	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 18 32N 7W
WELL	05-067-05080	SOUTHERN UTE 32-7 18-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 18 32N 7W
WELL	05-067-06833	SOUTHERN UTE 32-7 18-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 18 32N 7W
WELL	05-067-08249	SOUTHERN UTE 32-7 19-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 19 32N 7W
WELL	05-067-08259	SOUTHERN UTE 32-7 19-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 19 32N 7W
WELL	05-067-08292	SOUTHERN UTE 32-8 8-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 1 32N 8W
WELL	05-067-06209	SOUTHERN UTE 32-8 4-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 1 32N 8W
WELL	05-067-05164	SOUTHERN UTE 32-8 2-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 1 32N 8W

WELL	05-067-05202	SOUTHERN UTE 32-8 1-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 1 32N 8W
WELL	05-067-08293	SOUTHERN UTE 32-8 7-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 1 32N 8W
WELL	05-067-06204	SOUTHERN UTE 32-8 3-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 1 32N 8W
WELL	05-067-07089	SOUTHERN UTE 32-8 5-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 1 32N 8W
WELL	05-067-08234	SOUTHERN UTE 32-8 6-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 1 32N 8W
WELL	05-067-08288	SOUTHERN UTE 32-8 7-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 2 32N 8W
WELL	05-067-08230	SOUTHERN UTE 32-8 5-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 2 32N 8W
WELL	05-067-08289	SOUTHERN UTE 32-8 8-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 2 32N 8W
WELL	05-067-08287	SOUTHERN UTE 32-8 6-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 2 32N 8W
WELL	05-067-07093	SOUTHERN UTE 32-8 4-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 11 32N 8W
WELL	05-067-05135	SOUTHERN UTE 32-8 1-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 11 32N 8W
WELL	05-067-08240	SOUTHERN UTE 32-8 5-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 11 32N 8W

WELL	05-067-06237	SOUTHERN UTE 32-8 2-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 11 32N 8W
WELL	05-067-08236	SOUTHERN UTE 32-8 6-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 11 32N 8W
WELL	05-067-07092	SOUTHERN UTE 32-8 3-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 11 32N 8W
WELL	05-067-06251	SOUTHERN UTE 32-8 5-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 12 32N 8W
WELL	05-067-06193	SOUTHERN UTE 32-8 3-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 12 32N 8W
WELL	05-067-05112	SOUTHERN UTE 32-8 2-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 12 32N 8W
WELL	05-067-05127	SOUTHERN UTE 32-8 1-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 12 32N 8W
WELL	05-067-07094	SOUTHERN UTE 32-8 6-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 12 32N 8W
WELL	05-067-06192	SOUTHERN UTE 32-8 4-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 12 32N 8W
WELL	05-067-07104	SOUTHERN UTE 32-8 7-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 12 32N 8W
WELL	05-067-08235	SOUTHERN UTE 32-8 8-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 12 32N 8W
WELL	05-067-06487	SOUTHERN UTE 32-8 13-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 13 32N 8W

WELL	05-067-06236	SOUTHERN UTE 32-8 13-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 13 32N 8W
WELL	05-067-07105	SOUTHERN UTE 32-8 13-7	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 13 32N 8W
WELL	05-067-07106	SOUTHERN UTE 32-8 13-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 13 32N 8W
WELL	05-067-06384	SOUTHERN UTE 32-8 13-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 13 32N 8W
WELL	05-067-05073	SOUTHERN UTE 32-8 13-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 13 32N 8W
WELL	05-067-06172	SOUTHERN UTE 32-8 13-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 13 32N 8W
WELL	05-067-08239	SOUTHERN UTE 32-8 14-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 14 32N 8W
WELL	05-067-05089	SOUTHERN UTE 32-8 14-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 14 32N 8W
WELL	05-067-07107	SOUTHERN UTE 32-8 14-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 14 32N 8W
WELL	05-067-08242	SOUTHERN UTE 32-8 14-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 14 32N 8W
WELL	05-067-07108	SOUTHERN UTE 32-8 14-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 14 32N 8W
WELL	05-067-06173	SOUTHERN UTE 32-8 14-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 14 32N 8W

WELL	05-067-07346	SOUTHERN UTE 32-8 15-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 15 32N 8W
WELL	05-067-07179	SOUTHERN UTE 32-8 15-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 15 32N 8W
WELL	05-067-08170	SOUTHERN UTE 32-8 15-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 15 32N 8W
WELL	05-067-08154	SOUTHERN UTE 32-8 15-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 15 32N 8W
WELL	05-067-07284	SOUTHERN UTE 32-8 16-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 16 32N 8W
WELL	05-067-08155	SOUTHERN UTE 32-8 16-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 16 32N 8W
WELL	05-067-08156	SOUTHERN UTE 32-8 16-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 16 32N 8W
WELL	05-067-07347	SOUTHERN UTE 32-8 16-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 16 32N 8W
WELL	05-067-07348	SOUTHERN UTE 32-8 17-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 17 32N 8W
WELL	05-067-07345	SOUTHERN UTE 32-8 17-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 17 32N 8W
WELL	05-067-06930	SOUTHERN UTE 32-8 17-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 17 32N 8W
WELL	05-067-07372	SOUTHERN UTE 32-8 17-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 17 32N 8W

WELL	05-067-08152	SOUTHERN UTE 32-8 17-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 17 32N 8W
WELL	05-067-06676	SOUTHERN UTE 32-8 18-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 18 32N 8W
WELL	05-067-08151	SOUTHERN UTE 32-8 18-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 18 32N 8W
WELL	05-067-07350	SOUTHERN UTE 32-8 18-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 18 32N 8W
WELL	05-067-07349	SOUTHERN UTE 32-8 18-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 18 32N 8W
WELL	05-067-08255	SOUTHERN UTE 32-8 19-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 19 32N 8W
WELL	05-067-07351	SOUTHERN UTE 32-8 19-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 19 32N 8W
WELL	05-067-06253	SOUTHERN UTE 32-8 19-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 19 32N 8W
WELL	05-067-07285	SOUTHERN UTE 32-8 20-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 20 32N 8W
WELL	05-067-07352	SOUTHERN UTE 32-8 20-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 20 32N 8W
WELL	05-067-08258	SOUTHERN UTE 32-8 21-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 21 32N 8W
WELL	05-067-07353	SOUTHERN UTE 32-8 21-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 21 32N 8W

WELL	05-067-08165	SOUTHERN UTE 32-8 21-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 21 32N 8W
WELL	05-067-08256	SOUTHERN UTE 32-8 22-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 22 32N 8W
WELL	05-067-07290	SOUTHERN UTE 32-8 22-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 22 32N 8W
WELL	05-067-07289	SOUTHERN UTE 32-8 22-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 22 32N 8W
WELL	05-067-08294	SOUTHERN UTE 32-8 23-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 23 32N 8W
WELL	05-067-05785	SOUTHERN UTE 32-8 23-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 23 32N 8W
WELL	05-067-07109	SOUTHERN UTE 32-8 23-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 23 32N 8W
WELL	05-067-08271	SOUTHERN UTE 32-8 24-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 24 32N 8W
WELL	05-067-07110	SOUTHERN UTE 32-8 24-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 24 32N 8W
WELL	05-067-08250	SOUTHERN UTE 32-8 24-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 24 32N 8W
WELL	05-067-06166	SOUTHERN UTE 32-9 3-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 1 32N 9W
WELL	05-067-06055	SOUTHERN UTE 32-9 1-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 1 32N 9W

WELL	05-067-06241	SOUTHERN UTE 32-9 4-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 1 32N 9W
WELL	05-067-06240	SOUTHERN UTE 32-9 5-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 1 32N 9W
WELL	05-067-07017	SOUTHERN UTE 32-9 7-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 1 32N 9W
WELL	05-067-07115	SOUTHERN UTE 32-9 6-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 1 32N 9W
WELL	05-067-06165	SOUTHERN UTE 32-9 2-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 1 32N 9W
WELL	05-067-06167	SOUTHERN UTE 32-9 3-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 2 32N 9W
WELL	05-067-06303	SOUTHERN UTE 32-9 4-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 2 32N 9W
WELL	05-067-06239	SOUTHERN UTE 32-9 5-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 2 32N 9W
WELL	05-067-07095	SOUTHERN UTE 32-9 6-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 2 32N 9W
WELL	05-067-06148	SOUTHERN UTE 32-9 2-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 2 32N 9W
WELL	05-067-06056	SOUTHERN UTE 32-9 1-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 2 32N 9W
WELL	05-067-07096	SOUTHERN UTE 32-9 7-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 2 32N 9W

WELL	05-067-07313	SOUTHERN UTE 32-9 2-May	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 5 32N 9W
WELL	05-067-07340	SOUTHERN UTE 32-9 3-May	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 5 32N 9W
WELL	05-067-07341	SOUTHERN UTE 32-9 1-Jun	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 6 32N 9W
WELL	05-067-07749	SOUTHERN UTE 32-9 2-Jun	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 6 32N 9W
WELL	05-067-07640	SOUTHERN UTE 32-9 1-Jul	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 7 32N 9W
WELL	05-067-07302	SOUTHERN UTE 32-9 2-Jul	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 7 32N 9W
WELL	05-067-07832	SOUTHERN UTE 32-9 8-4 X	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 8 32N 9W
WELL	05-067-07322	SOUTHERN UTE 32-9 4-Aug	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 8 32N 9W
WELL	05-067-07321	SOUTHERN UTE 32-9 3-Aug	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 8 32N 9W
WELL	05-067-06168	SOUTHERN UTE 32-9 2-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 11 32N 9W
WELL	05-067-06238	SOUTHERN UTE 32-9 4-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 11 32N 9W
WELL	05-067-07097	SOUTHERN UTE 32-9 6-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 11 32N 9W

WELL	05-067-06369	SOUTHERN UTE 32-9 5-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 11 32N 9W
WELL	05-067-06057	SOUTHERN UTE 32-9 1-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 11 32N 9W
WELL	05-067-07652	SOUTHERN UTE 32-9 7-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 11 32N 9W
WELL	05-067-06169	SOUTHERN UTE 32-9 3-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 11 32N 9W
WELL	05-067-08166	SOUTHERN UTE 32-9 3-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 12 32N 9W
WELL	05-067-07291	SOUTHERN UTE 32-9 1-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 12 32N 9W
WELL	05-067-07292	SOUTHERN UTE 32-9 2-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 12 32N 9W
WELL	05-067-08269	SOUTHERN UTE 32-9 6-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 12 32N 9W
WELL	05-067-08162	SOUTHERN UTE 32-9 4-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 12 32N 9W
WELL	05-067-08268	SOUTHERN UTE 32-9 5-Dec	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 12 32N 9W
WELL	05-067-07180	SOUTHERN UTE 32-9 13-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 13 32N 9W
WELL	05-067-06174	SOUTHERN UTE 32-9 13-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 13 32N 9W

WELL	05-067-08144	SOUTHERN UTE 32-9 13-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 13 32N 9W
WELL	05-067-08163	SOUTHERN UTE 32-9 13-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 13 32N 9W
WELL	05-067-07293	SOUTHERN UTE 32-9 13-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 13 32N 9W
WELL	05-067-07605	SOUTHERN UTE 32-9 14-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 CNE 14 32N 9W
WELL	05-067-06345	SOUTHERN UTE 32-9 14-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 14 32N 9W
WELL	05-067-06385	SOUTHERN UTE 32-9 14-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 14 32N 9W
WELL	05-067-06346	SOUTHERN UTE 32-9 14-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 14 32N 9W
WELL	05-067-07616	SOUTHERN UTE 32-9 14-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 14 32N 9W
WELL	05-067-06813	SOUTHERN UTE 32-9 15-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 15 32N 9W
WELL	05-067-06812	SOUTHERN UTE 32-9 15-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 15 32N 9W
WELL	05-067-06811	SOUTHERN UTE 32-9 15-8	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 15 32N 9W
WELL	05-067-06810	SOUTHERN UTE 32-9 15-7	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 15 32N 9W

WELL	05-067-07315	SOUTHERN UTE 32-9 16-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 16 32N 9W
WELL	05-067-06754	SOUTHERN UTE 32-9 16-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 16 32N 9W
WELL	05-067-07314	SOUTHERN UTE 32-9 16-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 16 32N 9W
WELL	05-067-08140	SOUTHERN UTE 32-9 16-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 16 32N 9W
WELL	05-067-07324	SOUTHERN UTE 32-9 17-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 17 32N 9W
WELL	05-067-07323	SOUTHERN UTE 32-9 17-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 17 32N 9W
WELL	05-067-07325	SOUTHERN UTE 32-9 18-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 18 32N 9W
WELL	05-067-08270	SOUTHERN UTE 32-9 20-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 20 32N 9W
WELL	05-067-07326	SOUTHERN UTE 32-9 20-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 20 32N 9W
WELL	05-067-07181	SOUTHERN UTE 32-9 21-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 21 32N 9W
WELL	05-067-06383	SOUTHERN UTE 32-9 21-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 21 32N 9W
WELL	05-067-07297	SOUTHERN UTE 32-9 21-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 21 32N 9W

WELL	05-067-07169	SOUTHERN UTE 32-9 22-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 22 32N 9W
WELL	05-067-07294	SOUTHERN UTE 32-9 23-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 23 32N 9W
WELL	05-067-07098	SOUTHERN UTE 32-9 23-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 23 32N 9W
WELL	05-067-08254	SOUTHERN UTE 32-9 24-7	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 24 32N 9W
WELL	05-067-07099	SOUTHERN UTE 32-9 24-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 24 32N 9W
WELL	05-067-06353	SOUTHERN UTE 32-9 24-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 24 32N 9W
WELL	05-067-07892	FRANK DAVIS GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 2 33N 10W
WELL	05-067-08408	FRANK DAVIS GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 2 33N 10W
WELL	05-067-07526	FRANK DAVIS GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 3 33N 10W
WELL	05-067-08516	FRANK DAVIS GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 3 33N 10W
WELL	05-067-08508	JACQUES, THOMAS GAS UNIT G 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 10 33N 10W
		THOMAS JACQUEZ GU G	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-07722	1	10000	PR	38300	NENW 10 33N 10W
WELL	05-067-07036	ANIMAS 11-Mar	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 CSW 11 33N 10W
WELL	05-067-08713	PRESENTACION MEDINA GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 11 33N 10W
WELL	05-067-05596	ANIMAS 3-11 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 11 33N 10W
WELL	05-067-07471	MEDIAN,PRESENTACION GAS UT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 11 33N 10W
WELL	05-067-09002	ELMER DUNKEL GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 12 33N 10W
WELL	05-067-07455	ELMER DUNKEL GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 12 33N 10W
WELL	05-067-07265	DAVIES GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 13 33N 10W
WELL	05-067-07569	SOUTHERN UTE GAS UNIT QQ PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 13 33N 10W
WELL	05-067-08978	SOUTHERN UTE GAS UNIT QQ PLA-6 #2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 13 33N 10W
WELL	05-067-07590	THOMAS JACQUEZ GAS UNIT E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 14 33N 10W

WELL	05-067-08496	THOMAS JACQUEZ GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 14 33N 10W
WELL	05-067-07463	THOMAS JACQUEZ GU A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 14 33N 10W
WELL	05-067-08676	THOMAS JACQUEZ GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 15 33N 10W
WELL	05-067-07493	SOUTHERN UTE 33-10 15-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 15 33N 10W
WELL	05-067-07464	THOMAS JACQUEZ GU B PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 15 33N 10W
WELL	05-067-08833	SOUTHERN UTE 15-3 33-10	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 15 33N 10W
WELL	05-067-08762	SOUTHERN UTE 16-2;33-10 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 16 33N 10W
WELL	05-067-07489	SOUTHERN UTE 33-10 16-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 16 33N 10W
WELL	05-067-06478	SOUTHERN UTE 33-10 18-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 18 33N 10W
WELL	05-067-07360	SOUTHERN UTE 33-10 18-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 18 33N 10W
WELL	05-067-06396	SOUTHERN UTE 33-10 19-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 19 33N 10W

WELL	05-067-07362	SOUTHERN UTE 33-10 19-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 19 33N 10W
WELL	05-067-07361	SOUTHERN UTE 33-10 19-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 19 33N 10W
WELL	05-067-06461	SOUTHERN UTE 33-10 19-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 19 33N 10W
WELL	05-067-08366	SOUTHERN UTE 33-10 20-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 20 33N 10W
WELL	05-067-06606	SOUTHERN UTE 33-10 20-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 20 33N 10W
WELL	05-067-07510	SOUTHERN UTE 33-10 20-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 20 33N 10W
WELL	05-067-07591	SOUTHERN UTE 33-10 20-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 20 33N 10W
WELL	05-067-07356	SOUTHERN UTE 33-10 21-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 21 33N 10W
WELL	05-067-07490	SOUTHERN UTE 33-10 22-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 22 33N 10W
WELL	05-067-07363	SOUTHERN UTE 33-10 22-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 22 33N 10W
WELL	05-067-07364	SOUTHERN UTE 33-10 23-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 23 33N 10W
WELL	05-067-07612	SOUTHERN UTE 33-10 23-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 23 33N 10W

WELL	05-067-07287	SOUTHERN UTE 33-10 24-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 24 33N 10W
WELL	05-067-06067	CRAIG GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 24 33N 10W
WELL	05-067-06761	CRAIG GAS UNIT 3-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 24 33N 10W
WELL	05-067-06765	CRAIG GAS UNIT 2-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 24 33N 10W
WELL	05-067-06668	SHARP GAS UNIT 3-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 25 33N 10W
WELL	05-067-06330	SHARP GAS UNIT 1-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 25 33N 10W
WELL	05-067-06666	SHARP GAS UNIT 2-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 25 33N 10W
WELL	05-067-06043	SHARP GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 25 33N 10W
WELL	05-067-07266	M F SHARP GU A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 25 33N 10W
WELL	05-067-07734	SOUTHERN UTE 33-10 25-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 25 33N 10W
WELL	05-067-07922	MCKEE UTE 26-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 26 33N 10W
WELL	05-067-07365	SOUTHERN UTE 33-10 26-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 26 33N 10W

WELL	05-067-07288	SOUTHERN UTE 33-10 27-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 27 33N 10W
WELL	05-067-07592	SOUTHERN UTE 33-10 28-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 28 33N 10W
WELL	05-067-07357	SOUTHERN UTE 33-10 28-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 28 33N 10W
WELL	05-067-07528	SOUTHERN UTE 33-10 29-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 29 33N 10W
WELL	05-067-07366	SOUTHERN UTE 33-10 29-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 29 33N 10W
WELL	05-067-06682	SOUTHERN UTE 33-10 30-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 30 33N 10W
WELL	05-067-07486	ELDRIDGE 30-1 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 30 33N 10W
WELL	05-067-07696	SOUTHERN UTE 33-10 30-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 30 33N 10W
WELL	05-067-07367	SOUTHERN UTE 33-10 31-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 31 33N 10W
WELL	05-067-07487	ELDRIDGE 31-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 31 33N 10W
WELL	05-067-07369	SOUTHERN UTE 33-10 32-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 32 33N 10W
WELL	05-067-07368	SOUTHERN UTE 33-10 32-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 32 33N 10W

WELL	05-067-07465	CYRUS JOHNSON GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 33 33N 10W
WELL	05-067-07511	SOUTHERN UTE 33-10 33-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 33 33N 10W
WELL	05-067-07574	SOUTHERN UTE TRIBAL AA B PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 34 33N 10W
WELL	05-067-07311	SOUTHERN UTE May-35	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 35 33N 10W
WELL	05-067-07007	SOUTHERN UTE Apr-35	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 35 33N 10W
WELL	05-067-07312	BONDAD Jan-36	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 36 33N 10W
WELL	05-067-07767	WALTER OWENS GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 36 33N 10W
WELL	05-067-08505	SOUTHERN UTE 13-2R 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 13 33N 11W
WELL	05-067-07807	SOUTHERN UTE 13 2R	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 13 33N 11W
WELL	05-067-07385	SOUTHERN UTE 13 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 13 33N 11W
WELL	05-067-08627	SOUTHERN UTE 14-2 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 14 33N 11W

WELL	05-067-08512	SOUTHERN UTE 14-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 14 33N 11W
WELL	05-067-07407	SOUTHERN UTE 14 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 14 33N 11W
WELL	05-067-07408	SOUTHERN UTE 14 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 14 33N 11W
WELL	05-067-07660	SOUTHERN UTE 23 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 23 33N 11W
WELL	05-067-07386	SOUTHERN UTE 23 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 23 33N 11W
WELL	05-067-07405	SOUTHERN UTE 24 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 24 33N 11W
WELL	05-067-07406	SOUTHERN UTE 24 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 24 33N 11W
WELL	05-067-07432	ELDRIDGE 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 25 33N 11W
WELL	05-067-07172	ELDRIDGE 25 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 25 33N 11W
WELL	05-067-07061	SOUTHERN UTE 26-J 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 26 33N 11W
WELL	05-067-07282	SOUTHERN UTE 26-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 26 33N 11W
WELL	05-067-06456	SOUTHERN UTE 33-11 26-1U	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 26 33N 11W

WELL	05-067-05280	UTE 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 27 33N 11W
WELL	05-067-07283	SOUTHERN UTE 27-O 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 27 33N 11W
WELL	05-067-07805	SOUTHERN UTE 34 1R	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 34 33N 11W
WELL	05-067-07429	SOUTHERN UTE 35 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 35 33N 11W
WELL	05-067-07631	ELDRIDGE 36 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 36 33N 11W
WELL	05-067-07389	SOUTHERN UTE 36 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 36 33N 11W
WELL	05-067-06759	SOUTHERN UTE TRIBAL B 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 3 33N 6W
WELL	05-067-06635	SOUTHERN UTE 17-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 17 33N 6W
WELL	05-067-06634	SOUTHERN UTE 17-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 17 33N 6W
WELL	05-067-07201	STATE GAS UNIT CB 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 18 33N 6W
WELL	05-067-06679	BAIRD GAS UNIT 18-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 18 33N 6W
WELL	05-067-06644	BAIRD GAS UNIT 18-1 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 18 33N 6W

WELL	05-067-07025	STATE GAS COM BZ 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 19 33N 6W
WELL	05-067-06650	ROBERTSON 19-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 19 33N 6W
WELL	05-067-08023	STATE GAS COM BZ 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 19 33N 6W
WELL	05-067-08778	ROBERTSON GU 19-01 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 19 33N 6W
WELL	05-067-06636	SOUTHERN UTE 20-1B	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 20 33N 6W
WELL	05-067-06684	HOTT GAS UNIT 20-02(EPA) 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 20 33N 6W
WELL	05-067-06629	HOTT GAS UNIT 20-2 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 20 33N 6W
WELL	05-067-06762	SOUTHERN UTE TRIBAL 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 21 33N 6W
WELL	05-067-06687	SOUTHERN UTE TRIBAL 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 21 33N 6W
WELL	05-067-08032	SOUTHERN UTE 28-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 21 33N 6W
WELL	05-067-06617	SOUTHERN UTE 27-1B	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 27 33N 6W
WELL	05-067-06639	ANDERSON 28-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 28 33N 6W

WELL	05-067-06539	SOUTHERN UTE 28-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 28 33N 6W
WELL	05-067-06618	SOUTHERN UTE 29-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 29 33N 6W
WELL	05-067-06905	HOTT 29-2 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 29 33N 6W
WELL	05-067-06783	SOUTHERN UTE 29-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 29 33N 6W
WELL	05-067-06630	HOTT GAS UNIT 29-02 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 29 33N 6W
WELL	05-067-06610	HOTT 30-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 30 33N 6W
WELL	05-067-07087	HOTT 30-1 UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 30 33N 6W
WELL	05-067-06611	HOTT 30-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 30 33N 6W
WELL	05-067-06705	HORTHER 31-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 31 33N 6W
WELL	05-067-06640	TAICHERT 31-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 31 33N 6W
WELL	05-067-06641	TAICHERT 32-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 32 33N 6W
WELL	05-067-06631	CARLSON 32-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 32 33N 6W

WELL	05-067-07077	SOUTHERN UTE GAS UNIT AA 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 33 33N 6W
WELL	05-067-08026	TAICHERT GAS UNIT 32-2 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 33 33N 6W
WELL	05-067-06706	KOEHLER 33-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 33 33N 6W
WELL	05-067-07979	SOUTHERN UTE GAS UNIT U 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 34 33N 6W
WELL	05-067-06626	CUNDIFF 34-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 34 33N 6W
WELL	05-067-06633	SOUTHERN UTE 1-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 1 33N 7W
WELL	05-067-07079	SOUTHERN UTE TRIBAL K 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 5 33N 7W
WELL	05-067-07023	SOUTHERN UTE TRIBAL O 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 5 33N 7W
WELL	05-067-07977	SOUTHERN UTE TRIBAL AW 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 6 33N 7W
WELL	05-067-07978	SOUTHERN UTE GAS UNIT AX 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 6 33N 7W
WELL	05-067-07052	SOUTHERN UTE GAS UNIT P 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 7 33N 7W
WELL	05-067-08826	LUCERO GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 7 33N 7W

WELL	05-067-06983	LUCERO GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 7 33N 7W
WELL	05-067-08782	SOUTHERN UTE GAS UNIT P 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 7 33N 7W
WELL	05-067-06359	SOUTHERN UTE 1-8 GAS UNIT 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 8 33N 7W
WELL	05-067-07080	SOUTHERN UTE TRIBAL V 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 8 33N 7W
WELL	05-067-06003	SOUTHERN UTE GAS UNIT 1-8 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 8 33N 7W
WELL	05-067-07143	SOUTHERN UTE GAS UNIT GG 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 12 33N 7W
WELL	05-067-07050	SOUTHERN UTE TRIBAL Y 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 13 33N 7W
WELL	05-067-06916	SOUTHERN UTE TRIBAL G 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 13 33N 7W
WELL	05-067-08028	SOUTHERN UTE TRIBAL G #2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 13 33N 7W
WELL	05-067-08029	SOUTHERN UTE TRIBAL Y #2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 13 33N 7W
WELL	05-067-08033	SOUTHERN UTE GAS UNIT Z 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 13 33N 7W
WELL	05-067-07144	SOUTHERN UTE TRIBAL X 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 14 33N 7W

WELL	05-067-06827	UTE GAS UNIT AB 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 16 33N 7W
WELL	05-067-06828	SOUTHERN UTE GAS COM F 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 17 33N 7W
WELL	05-067-06741	SOUTHERN UTE TRIBAL D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 17 33N 7W
WELL	05-067-08812	UTE GAS UNIT AC 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 18 33N 7W
WELL	05-067-06829	UTE GAS UNIT AC 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 18 33N 7W
WELL	05-067-08806	SOUTHERN UTE GAS UNIT Q 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 19 33N 7W
WELL	05-067-08645	SIMMS GAS UNIT D 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 19 33N 7W
WELL	05-067-06839	SOUTHERN UTE GAS UNIT Q 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 19 33N 7W
WELL	05-067-06820	SIMS GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 19 33N 7W
WELL	05-067-06746	UTE GAS UNIT 'AA' 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 20 33N 7W
WELL	05-067-06797	UTE GAS UNIT AA 1S	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 20 33N 7W
WELL	05-067-06836	BEUTEN GAS UNIT B 1S	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 20 33N 7W

WELL	05-067-06725	F W BEUTEN UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 20 33N 7W
WELL	05-067-06683	SOUTHERN UTE GAS COM B 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 21 33N 7W
WELL	05-067-06798	SOUTHERN UTE TRIBAL E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 21 33N 7W
WELL	05-067-07045	SOUTHERN UTE GAS UNIT Z 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 24 33N 7W
WELL	05-067-07448	UTE 33-7-24 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 24 33N 7W
WELL	05-067-07014	ARTHUR H JONES GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 26 33N 7W
WELL	05-067-07024	SOUTHERN UTE TRIBAL L 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 27 33N 7W
WELL	05-067-06998	PARRY GAS UNIT E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 27 33N 7W
WELL	05-067-06799	SALVADOR GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 28 33N 7W
WELL	05-067-06830	SOUTHERN UTE TRIBAL F 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 28 33N 7W
WELL	05-067-06800	BEUTEN GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 29 33N 7W
WELL	05-067-06831	BEUTEN GAS UNIT A 1S	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 29 33N 7W

WELL	05-067-06344	SIMMS GAS UNIT 1A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 30 33N 7W
WELL	05-067-05312	SIMMS GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 30 33N 7W
WELL	05-067-07026	SIMMS GAS UNIT E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 30 33N 7W
WELL	05-067-06329	WIRT GAS UNIT A 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 31 33N 7W
WELL	05-067-05226	WILDE GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 31 33N 7W
WELL	05-067-05239	WIRT GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 31 33N 7W
WELL	05-067-07037	SPANISH FORK GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 34 33N 7W
WELL	05-067-06714	MOFFETT GAS UNIT B 1A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 34 33N 7W
WELL	05-067-08808	SPANISH FORKS GU B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 34 33N 7W
WELL	05-067-06371	MOFFETT GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 34 33N 7W
WELL	05-067-06999	SPANISH FORK GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 34 33N 7W
WELL	05-067-06984	ALBERTA PARRY GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 35 33N 7W

WELL	05-067-09140	SIMMONS GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 1 33N 8W
WELL	05-067-09312	SIMMONS GAS UNIT A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 1 33N 8W
WELL	05-067-08953	SIMMONS GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 1 33N 8W
WELL	05-067-07861	SIMMONS GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 1 33N 8W
WELL	05-067-08983	SEMLER GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 1 33N 8W
WELL	05-067-07873	SEMLER GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 1 33N 8W
WELL	05-067-08633	BRADFIELD GAS UNIT CH 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 2 33N 8W
WELL	05-067-07836	BRADFIELD GAS UNIT CH 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 2 33N 8W
WELL	05-067-07870	BONAFACIO GALLEGOS GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 2 33N 8W
WELL	05-067-09059	GALLEGOS-BONIFACIO GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 2 33N 8W
WELL	05-067-06738	FORD GAS UNIT F 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 3 33N 8W
		KLUSMAN GAS UNIT A	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-07862	1	10000	PR	38300	NENW 3 33N 8W
WELL	05-067-06181	FORD GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 3 33N 8W
WELL	05-067-06753	FORD GAS UNIT D 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 3 33N 8W
WELL	05-067-06339	FORD GAS UNIT "E" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 3 33N 8W
WELL	05-067-07860	LILA CUMMINS GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 4 33N 8W
WELL	05-067-08819	CUMMINS,LILA GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 4 33N 8W
WELL	05-067-07329	J W WARD GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 5 33N 8W
WELL	05-067-08818	WARD J.W.GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 5 33N 8W
WELL	05-067-08874	LECHNER OPAL GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 6 33N 8W
WELL	05-067-07336	OPAL LECHNER GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 6 33N 8W
WELL	05-067-08831	KLUSMAN RANCES GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 11 33N 8W
WELL	05-067-06985	KLUSMAN RANCHES GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 11 33N 8W

WELL	05-067-06997	TILLMAN BURCH GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 12 33N 8W
WELL	05-067-06986	FARMER GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 12 33N 8W
WELL	05-067-08639	TILLMAN BURCH GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 12 33N 8W
WELL	05-067-08638	FARMER GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 12 33N 8W
WELL	05-067-07035	SOUTHERN UTE GAS UNIT M 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 13 33N 8W
WELL	05-067-07029	SOUTHERN UTE GAS UNIT N 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 13 33N 8W
WELL	05-067-08918	SOUTHERN UTE GAS UNIT M 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 13 33N 8W
WELL	05-067-08792	SOUTHERN UTE GAS UNIT N 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 13 33N 8W
WELL	05-067-08893	SOUTHERN UTE GAS UNIT AK 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 14 33N 8W
WELL	05-067-08894	SOUTHERN UTE GAS UNIT AK 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 14 33N 8W
WELL	05-067-06299	PAN AM FEE GAS UNIT A 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 22 33N 8W
WELL	05-067-05777	PAN AM FEE GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 22 33N 8W

WELL	05-067-06760	PAN AMERICAN FEE GAS UNIT B 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 23 33N 8W
WELL	05-067-07000	DEKAY GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 23 33N 8W
WELL	05-067-05796	PAN AM FEE GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 23 33N 8W
WELL	05-067-06662	AMOCO GAS UNIT 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 24 33N 8W
WELL	05-067-06244	AMOCO GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 24 33N 8W
WELL	05-067-05274	WIRT GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 25 33N 8W
WELL	05-067-06298	WIRT GAS UNIT C 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 25 33N 8W
WELL	05-067-08280	SOUTHERN UTE 33-8 30-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 30 33N 8W
WELL	05-067-08283	SOUTHERN UTE 33-8 31-6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 31 33N 8W
WELL	05-067-07019	SOUTHERN UTE 33-8 31-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 31 33N 8W
WELL	05-067-07619	SOUTHERN UTE 33-8 31-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 31 33N 8W
WELL	05-067-06308	SOUTHERN UTE 33-8 31-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 31 33N 8W

WELL	05-067-06058	SOUTHERN UTE 33-8 31-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 31 33N 8W
WELL	05-067-07618	SOUTHERN UTE 33-8 31-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 31 33N 8W
WELL	05-067-08281	SOUTHERN UTE 33-8 31-7	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 31 33N 8W
WELL	05-067-08279	SOUTHERN UTE 33-8 32-9	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 32 33N 8W
WELL	05-067-07021	SOUTHERN UTE 33-8 32-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 32 33N 8W
WELL	05-067-07022	SOUTHERN UTE 33-8 32-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 32 33N 8W
WELL	05-067-07995	SOUTHERN UTE 33-8 32-8	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 32 33N 8W
WELL	05-067-07536	SOUTHERN UTE 33-8 32-5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 32 33N 8W
WELL	05-067-06059	SOUTHERN UTE 33-8 32-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 32 33N 8W
WELL	05-067-08278	SOUTHERN UTE 33-8 32-10	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 32 33N 8W
WELL	05-067-06375	SOUTHERN UTE 33-8 32-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 32 33N 8W
WELL	05-067-06297	BRIGGS GAS UNIT 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 35 33N 8W

WELL	05-067-05244	WILDE GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 36 33N 8W
WELL	05-067-06296	WILDE GAS UNIT B 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 36 33N 8W
WELL	05-067-05225	WIRT GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 36 33N 8W
WELL	05-067-06328	WIRT GAS UNIT B 1-A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 36 33N 8W
WELL	05-067-08773	BARNES GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 1 33N 9W
WELL	05-067-06965	BARNES GAS UNIT B PLA 6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 1 33N 9W
WELL	05-067-06980	MAYFIELD-MELTON GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 1 33N 9W
WELL	05-067-09044	MAYFIELD MELTON GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 1 33N 9W
WELL	05-067-06966	BARNES GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 2 33N 9W
WELL	05-067-08731	BARNES GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 2 33N 9W
WELL	05-067-08769	BARNES-LEIDY GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 2 33N 9W
		BARNES-LEIDY GAS UNIT	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-06976	1	10000	PR	38300	SWNW 2 33N 9W
WELL	05-067-06969	BARNES-LEIDY GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 3 33N 9W
WELL	05-067-07609	FC LIEDY COM 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 3 33N 9W
WELL	05-067-08207	BARNES LEIDY GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 3 33N 9W
WELL	05-067-08707	FC LEIDY COM FT 001 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 3 33N 9W
WELL	05-067-08739	PETER PHILLIPS GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 4 33N 9W
WELL	05-067-07028	PETER PHILLIPS GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 4 33N 9W
WELL	05-067-07027	JOHN BARNES GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 4 33N 9W
WELL	05-067-08860	BARNES,JOHN GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 4 33N 9W
WELL	05-067-08794	CLOVIS G U A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 6 33N 9W
WELL	05-067-07595	HUNGERFORD GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 6 33N 9W
		HUNGERFORD GAS UNIT A	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-08423	2	10000	PR	38300	SENE 6 33N 9W
WELL	05-067-06907	CLOVIS GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 6 33N 9W
WELL	05-067-08650	SHORT LYLE GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 7 33N 9W
WELL	05-067-07146	ALVA SHORT GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 7 33N 9W
WELL	05-067-08425	ALVA SHORT GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 7 33N 9W
WELL	05-067-06911	LYLE SHORT GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 7 33N 9W
WELL	05-067-07128	ORAN W SHORT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 8 33N 9W
WELL	05-067-08680	CLOVIS GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 8 33N 9W
WELL	05-067-08524	ORAN W SHORT GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 8 33N 9W
WELL	05-067-06906	CLOVIS GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 8 33N 9W
WELL	05-067-08891	FC SOUTHERN UTE COM 001 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 9 33N 9W
WELL	05-067-07654	FC SOUTHERN UTE COM 5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 9 33N 9W
WELL	05-067-07479	SOUTHERN UTE FC 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 9 33N 9W

WELL	05-067-08776	FC SOUTHERN UTE COM 005 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 9 33N 9W
WELL	05-067-08889	FC SOUTHERN UTE COM 002 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 10 33N 9W
WELL	05-067-07480	FC SOUTHERN UTE 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 10 33N 9W
WELL	05-067-09056	FC ARMSTRONG COM 001 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 10 33N 9W
WELL	05-067-07610	FC ARMSTRONG COM 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 10 33N 9W
WELL	05-067-08827	FC SOUTHERN UTE COM 004/FT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 11 33N 9W
WELL	05-067-09151	FC SOUTHERN UTE COM 003 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 11 33N 9W
WELL	05-067-07481	FC SOUTHERN UTE 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 11 33N 9W
WELL	05-067-07482	FC SOUTHERN UTE COM 004/FT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 11 33N 9W
WELL	05-067-09058	FC SOUTHERN UTE COM 006 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 12 33N 9W
WELL	05-067-07653	FC SOUTHERN UTE COM 6	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 12 33N 9W

WELL	05-067-09051	WARREN DAVIS GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 13 33N 9W
WELL	05-067-07956	WARREN DAVIS GAS UNIT C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 13 33N 9W
WELL	05-067-07877	MCCARVILLE GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 14 33N 9W
WELL	05-067-09034	MCCARVILLE GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 14 33N 9W
WELL	05-067-08817	MCCARVILLE GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 14 33N 9W
WELL	05-067-07264	MCCARVILLE GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 14 33N 9W
WELL	05-067-07307	ARVIL BROWN 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 15 33N 9W
WELL	05-067-08807	BROWN, ARVIL 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 15 33N 9W
WELL	05-067-07006	SOUTHERN UTE 1-16X	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 16 33N 9W
WELL	05-067-06946	SOUTHERN UTE 16-Jul	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 16 33N 9W
WELL	05-067-05415	SOUTHERN UTE 16-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 16 33N 9W
WELL	05-067-08203	SOUTHERN UTE 2-16 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 16 33N 9W

WELL	05-067-07611	ROY ESHELMAN GAS UNIT PLA 6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 18 33N 9W
WELL	05-067-08908	SHORT, ALVA GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 18 33N 9W
WELL	05-067-07129	ALVA SHORT GAS UNIT B/PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 18 33N 9W
WELL	05-067-08493	ESHELMAN ROY GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 18 33N 9W
WELL	05-067-08749	RAYMOND KOON GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 19 33N 9W
WELL	05-067-06685	KOON GAS UNIT 2-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 19 33N 9W
WELL	05-067-06331	KOON GAS UNIT 1E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 19 33N 9W
WELL	05-067-07462	RAYMOND KOON GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 19 33N 9W
WELL	05-067-07599	SOUTHERN UTE TRIBAL AAA 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 19 33N 9W
WELL	05-067-06695	KOON GAS UNIT 3-E	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 19 33N 9W
WELL	05-067-05382	SOUTHERN UTE 2-21X 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 21 33N 9W

WELL	05-067-07310	LASH UTE 21-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 21 33N 9W
WELL	05-067-09043	LASH UTE 1-21 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 21 33N 9W
WELL	05-067-09046	SOUTHERN UTE 2-21X 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 21 33N 9W
WELL	05-067-07883	MAESTAS GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 23 33N 9W
WELL	05-067-08914	MCCARVILLE GAS UNIT C #2 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 23 33N 9W
WELL	05-067-09032	MAESTAS GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 23 33N 9W
WELL	05-067-07869	MCCARVILLE GAS UNIT C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 23 33N 9W
WELL	05-067-09004	FED.LAND BANK GAS UNIT G 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 24 33N 9W
WELL	05-067-09082	MARTINEZ GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 24 33N 9W
WELL	05-067-07878	FEDERAL LAND BANK GAS UNIT G 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 24 33N 9W
WELL	05-067-07643	SOUTHERN UTE GAS UNIT JJ PLA 6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 29 33N 9W

WELL	05-067-07354	SOUTHERN UTE 33-9 29-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 29 33N 9W
WELL	05-067-08143	SOUTHERN UTE 33-9 29-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 29 33N 9W
WELL	05-067-08354	SOUTHERN UTE 33-9 29-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 29 33N 9W
WELL	05-067-07589	ROY BROWN GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 30 33N 9W
WELL	05-067-08115	SOUTHERN UTE 33-9 30-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 30 33N 9W
WELL	05-067-06184	SOUTHERN UTE 33-9 30-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 30 33N 9W
WELL	05-067-08689	ROY BROWN GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 30 33N 9W
WELL	05-067-08712	SOUTHERN UTE 30-3 33-9	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 30 33N 9W
WELL	05-067-08507	MOORE,D.I. GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 31 33N 9W
WELL	05-067-07634	DJ MOORE GAS UNIT A PLA-6 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 31 33N 9W
WELL	05-067-07768	SOUTHERN UTE33-9` 32-2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 32 33N 9W
WELL	05-067-07355	SOUTHERN UTE 33-9 32-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 32 33N 9W

WELL	05-067-08353	SOUTHERN UTE 33-9 32-4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 32 33N 9W
WELL	05-067-08153	SOUTHERN 33-9 32-3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 32 33N 9W
WELL	05-067-06715	FEDERAL 2L-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 2 34N 6W
WELL	05-067-07056	FISCHER-MARK FEDERAL B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 3 34N 6W
WELL	05-067-08649	LEE FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 3 34N 6W
WELL	05-067-07067	LEE FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 3 34N 6W
WELL	05-067-07331	FEDERAL 1-Apr	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 4 34N 6W
WELL	05-067-07073	FISCHER-MARK FEDERAL "B" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 4 34N 6W
WELL	05-067-07135	EVELYN PAYNE GU G 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 5 34N 6W
WELL	05-067-07332	FEDERAL 1-May	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 5 34N 6W
WELL	05-067-07446	K-G TRUST GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 6 34N 6W
WELL	05-067-08921	KG TRUST GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 6 34N 6W

WELL	05-067-07187	BEAVER CREEK GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 6 34N 6W
WELL	05-067-08923	BEAVER CREEK GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 6 34N 6W
WELL	05-067-07395	MORRISON FED GU G 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 7 34N 6W
WELL	05-067-08878	LUTER FEDERAL CU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 7 34N 6W
WELL	05-067-08858	STATE GAS COM MZ 1R	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 7 34N 6W
WELL	05-067-07430	LUTER FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 7 34N 6W
WELL	05-067-08869	MORRISON FED.GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 7 34N 6W
WELL	05-067-07333	FEDERAL 1-Aug	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 8 34N 6W
WELL	05-067-07058	MORRISON FEDERAL GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 8 34N 6W
WELL	05-067-08949	MORRISON FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 8 34N 6W
WELL	05-067-07057	FISCHER-MARK FEDERAL A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 9 34N 6W

WELL	05-067-09088	ARCHULETA DIX G.U. 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 9 34N 6W
WELL	05-067-07038	ARCHULETA/DIX GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 9 34N 6W
WELL	05-067-09076	MERRY FEDERAL G. U. 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 10 34N 6W
WELL	05-067-08862	FRAHM FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 10 34N 6W
WELL	05-067-07068	MERRY FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 10 34N 6W
WELL	05-067-07817	FRAHM FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 10 34N 6W
WELL	05-067-06717	FRAHM GAS UNIT 15-01	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 15 34N 6W
WELL	05-067-06727	IVERS 16-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 16 34N 6W
WELL	05-067-09040	MORRISON,HUBERT GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 17 34N 6W
WELL	05-067-06899	HUBERT MORRISON GAS UT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 17 34N 6W
		BEAVER CREEK GU B	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-07457	1	10000	PR	38300	SENW 18 34N 6W
WELL	05-067-06532	HARPER 1-18U	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 18 34N 6W
WELL	05-067-08214	BEAVER CREEK GU B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 18 34N 6W
WELL	05-067-06996	BOONE GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 19 34N 6W
WELL	05-067-06356	WRIGHT 19-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 19 34N 6W
WELL	05-067-06285	SMITH 1-20 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 20 34N 6W
WELL	05-067-06483	PINE RIVER UNIT 29-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 29 34N 6W
WELL	05-067-06243	PINE RIVER UNIT 30-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 30 34N 6W
WELL	05-067-06481	PINE RIVER UNIT 31-Mar	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 31 34N 6W
WELL	05-067-06482	PINE RIVER UNIT Apr-32	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 32 34N 6W
WELL	05-067-07557	NEVA DOVE GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 1 34N 7W
WELL	05-067-07556	TALIAFERRO TRUST GU A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 1 34N 7W
WELL	05-067-08412	DOVE,NEVA GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 1 34N 7W

WELL	05-067-08500	TALIAFERRO TRUST GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 1 34N 7W
WELL	05-067-07558	SOSSAMAN*DWIGHT GU A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 2 34N 7W
WELL	05-067-08675	PAISLEY GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 2 34N 7W
WELL	05-067-08982	SOSSAMAN DWIGHT GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 2 34N 7W
WELL	05-067-07818	PAISLEY GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 2 34N 7W
WELL	05-067-09001	KEATING GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 3 34N 7W
WELL	05-067-07185	KEATING GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 3 34N 7W
WELL	05-067-08722	CAHOON GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 3 34N 7W
WELL	05-067-07188	CAHOON GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 3 34N 7W
WELL	05-067-07431	SMITH GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 4 34N 7W
WELL	05-067-07501	SMITH WOLTER GU B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 4 34N 7W
		SMITH WOLTER GAS UNIT	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-08984	2	10000	PR	38300	NWNE 5 34N 7W
WELL	05-067-06373	GEARHART 5-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 5 34N 7W
WELL	05-067-07236	SMITH-WOLTER GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 5 34N 7W
WELL	05-067-06362	GEARHART 6-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 6 34N 7W
WELL	05-067-08378	GEARHART GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 6 34N 7W
WELL	05-067-07136	GEARHART GU B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 6 34N 7W
WELL	05-067-08679	GEARHART 1-6 GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 6 34N 7W
WELL	05-067-07189	HOLMAN CANYON GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 7 34N 7W
WELL	05-067-08720	HOLMAN CANYON GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 7 34N 7W
WELL	05-067-06357	NELEIGH 7-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 7 34N 7W
WELL	05-067-08946	JONES LAURANCE GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 7 34N 7W
WELL	05-067-06856	GARY BEEBE GAS UNIT "B" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 7 34N 7W

WELL	05-067-07854	JONES,LAURANCE GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 7 34N 7W
WELL	05-067-08725	NELEIGHT 1-7 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 7 34N 7W
WELL	05-067-08909	EMMA MCCARTY GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 CNE 8 34N 7W
WELL	05-067-08663	BUSH FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 8 34N 7W
WELL	05-067-09334	MCCARTY, EMMA GAS UNIT A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 8 34N 7W
WELL	05-067-07856	EMMA MCCARTY GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 8 34N 7W
WELL	05-067-08997	GEARHART GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 8 34N 7W
WELL	05-067-06852	REED GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 8 34N 7W
WELL	05-067-07114	BUSH FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 8 34N 7W
WELL	05-067-09160	MCCARTY, EMMA GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 8 34N 7W
WELL	05-067-07425	GEARHART GAS UNIT C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 8 34N 7W

WELL	05-067-06563	FRENCH 1-9U	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 9 34N 7W
WELL	05-067-07202	LEPLATT GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 9 34N 7W
WELL	05-067-08351	LE PLATT GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 9 34N 7W
WELL	05-067-07191	THACKER GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 9 34N 7W
WELL	05-067-09021	KNIGHT GAS UNIT E 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 9 34N 7W
WELL	05-067-07228	KNIGHT GAS UNIT E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 9 34N 7W
WELL	05-067-09019	FRENCH GAS UNIT 1-9U 2R	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 9 34N 7W
WELL	05-067-06322	UTE 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 10 34N 7W
WELL	05-067-06724	MARTIN, JOE 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 10 34N 7W
WELL	05-067-08655	MARTIN,JOE GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 10 34N 7W
WELL	05-067-08709	MANKINS-HOWARD GAS UNIT 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 10 34N 7W
WELL	05-067-08208	UTE 1-10 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 10 34N 7W

WELL	05-067-06726	MANKINS-HOWARD 10-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 10 34N 7W
WELL	05-067-07988	SO. UTE GAS UNIT "AF" #1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 10 34N 7W
WELL	05-067-06743	LE PLATT 11-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 11 34N 7W
WELL	05-067-08948	LE PLATT GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 11 34N 7W
WELL	05-067-07980	SO UTE TRIBAL AI 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 11 34N 7W
WELL	05-067-06547	HAYS 1-11U 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 11 34N 7W
WELL	05-067-08931	LEPLATT GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 11 34N 7W
WELL	05-067-08296	LUDWIG GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 12 34N 7W
WELL	05-067-07960	FLOREINE HUDSPETH GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 12 34N 7W
WELL	05-067-08937	FLOREINE HUDSPETH GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 12 34N 7W
WELL	05-067-07433	LUDWIG GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 12 34N 7W
		SITTON 01-13 UNIT F	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-06516	1	10000	PR	38300	NENE 13 34N 7W
WELL	05-067-08934	SITTON GAS UNIT 1-13 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 13 34N 7W
WELL	05-067-08870	SNOOKS GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 14 34N 7W
WELL	05-067-07830	SNOOKS GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 14 34N 7W
WELL	05-067-07849	GOSNEY GAS COM "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 15 34N 7W
WELL	05-067-08809	GOSNEY GAS COM A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 15 34N 7W
WELL	05-067-08211	SITTON FEDERAL GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 15 34N 7W
WELL	05-067-06544	DUNAVANT 1-15U	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 15 34N 7W
WELL	05-067-09035	DUNAVANT GAS UNIT 1-15U 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 15 34N 7W
WELL	05-067-07199	SITTON FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 15 34N 7W
WELL	05-067-06567	COUCH 1-16U	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 16 34N 7W
WELL	05-067-07981	BAIRD GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 16 34N 7W
		STATE GAS COM CF	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-08981	2	10000	PR	38300	SENE 16 34N 7W
WELL	05-067-07927	STATE GAS COM "CF" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 16 34N 7W
WELL	05-067-09017	BAYFIELD FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 17 34N 7W
WELL	05-067-07845	ROBERT L MCCOY GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 17 34N 7W
WELL	05-067-07852	STATE GAS COM "CD" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 17 34N 7W
WELL	05-067-08511	STATE GAS COM CD 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 17 34N 7W
WELL	05-067-07154	BAYFIELD FEDERAL GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 17 34N 7W
WELL	05-067-06613	DOLLAHON 18U-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 18 34N 7W
WELL	05-067-07846	ROBERT MCCOY GAS UNIT "B" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 18 34N 7W
WELL	05-067-09138	DOLLAHON 18U-1 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 18 34N 7W
WELL	05-067-09061	DOLLAHON 18U-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 18 34N 7W
		KAIME FEDERAL GAS UNIT	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-09060	2	10000	PR	38300	SWNE 18 34N 7W
WELL	05-067-07155	KAIME FEDERAL GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 18 34N 7W
WELL	05-067-06845	PAUL MARTIN GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 19 34N 7W
WELL	05-067-09145	MARTIN,PAUL B, GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 19 34N 7W
WELL	05-067-09146	MARTIN,PAUL B,GAS UNIT A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 19 34N 7W
WELL	05-067-08662	MARTIN, PAUL B. GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 19 34N 7W
WELL	05-067-07834	BRUCE COLVIN GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 19 34N 7W
WELL	05-067-07850	KNIGHT GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 20 34N 7W
WELL	05-067-06846	H N PEARSON A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 20 34N 7W
WELL	05-067-06704	SOUTHERN UTE 21-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 21 34N 7W
WELL	05-067-07858	GIG L SHAPIRO GU "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 21 34N 7W
WELL	05-067-07982	SOUTHERN UTE G.U."AG" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 22 34N 7W
WELL	05-067-06530	SOUTHERN UTE 22-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 22 34N 7W

WELL	05-067-06702	SOUTHERN UTE B D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 23 34N 7W
WELL	05-067-06703	SOUTHERN UTE GAS UNIT BE 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 23 34N 7W
WELL	05-067-06363	STATE 24-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 24 34N 7W
WELL	05-067-06851	GARY BEEBE GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 25 34N 7W
WELL	05-067-06723	SOUTHERN UTE GAS UNIT BF 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 26 34N 7W
WELL	05-067-06713	SOUTHERN UTE GAS UNIT BH 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 27 34N 7W
WELL	05-067-06529	SOUTHERN UTE GAS UNIT BG 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 27 34N 7W
WELL	05-067-07866	MCCATHRON GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 28 34N 7W
WELL	05-067-07961	C.V. THOMPSON ET UX G. U. 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 28 34N 7W
WELL	05-067-09204	JAMES GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 30 34N 7W
WELL	05-067-09205	JAMES GAS UNIT A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 30 34N 7W
WELL	05-067-07983	E.E. PRESTON GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 30 34N 7W

WELL	05-067-09092	WAYT,BUFORD G.U.A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 31 34N 7W
WELL	05-067-09075	WAYT,BUFORD G.U.A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 31 34N 7W
WELL	05-067-09090	FAIRFIELD FARMS G.U. 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 31 34N 7W
WELL	05-067-09065	FAIRFIELD FARMS G.U. 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 31 34N 7W
WELL	05-067-06728	FAIRFIELD FARMS GAS UNIT # 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 31 34N 7W
WELL	05-067-06875	BUFORD WAYT GAS UT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 31 34N 7W
WELL	05-067-06527	SOUTHERN UTE UNIT 1 Jan-32	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 32 34N 7W
WELL	05-067-06528	SOUTHERN UTE Jan-33	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 33 34N 7W
WELL	05-067-09064	RICHARDSON G.U. G 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 1 34N 8W
WELL	05-067-06455	RICHARDSON 1-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 1 34N 8W
WELL	05-067-09062	BURKETT G.U.A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 1 34N 8W
WELL	05-067-07059	BURKETT GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 1 34N 8W

WELL	05-067-07752	RICHARDSON GAS UNIT G 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 1 34N 8W
WELL	05-067-07774	RICHARDSON GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 2 34N 8W
WELL	05-067-09066	FEDERAL 1-2 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 2 34N 8W
WELL	05-067-07853	FEDERAL 1-2 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 2 34N 8W
WELL	05-067-06993	LEMON GAS UNIT F 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 7 34N 8W
WELL	05-067-06612	HANSTEDT, DEKAY, CARDELL 7U-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 7 34N 8W
WELL	05-067-08363	HANSTEDT GAS UNIT 07U-01 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 7 34N 8W
WELL	05-067-09172	HANSTEDT GAS UNIT 07U-1 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 7 34N 8W
WELL	05-067-09215	LEMON GAS UNIT F 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 7 34N 8W
WELL	05-067-08330	LEMON GAS UNIT F 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 7 34N 8W
WELL	05-067-09171	HANSTEDT GAS UNIT 7U-1 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 7 34N 8W
WELL	05-067-08686	SUNDANCE GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 8 34N 8W

WELL	05-067-08685	SUNDANCE GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 8 34N 8W
WELL	05-067-06991	LEMON GAS UNIT G 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 8 34N 8W
WELL	05-067-07824	JAMES COLE GAS UNIT "B" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 8 34N 8W
WELL	05-067-08752	COLE,JAMES GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 8 34N 8W
WELL	05-067-08352	LEMON GAS UNIT G 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 8 34N 8W
WELL	05-067-09236	DOWNING, RALPH GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 9 34N 8W
WELL	05-067-08499	DOWING RALPH GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 9 34N 8W
WELL	05-067-07546	TINKER 2-9 GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 9 34N 8W
WELL	05-067-07002	SALLY JO LORETT GAS UT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 9 34N 8W
WELL	05-067-07003	RALPH DOWNING GAS UT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 9 34N 8W
WELL	05-067-08213	TINKER 2-9 GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 9 34N 8W

WELL	05-067-09206	LORETT,SALLY JO GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 9 34N 8W
WELL	05-067-08497	LORETT SALLY JO G.U. A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 9 34N 8W
WELL	05-067-06559	MAYFIELD GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 10 34N 8W
WELL	05-067-08936	MAYFIELD GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 10 34N 8W
WELL	05-067-08935	MAYFIELD GAS UNIT A #2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 10 34N 8W
WELL	05-067-06614	MAYFIELD GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 10 34N 8W
WELL	05-067-07791	TINKER GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 10 34N 8W
WELL	05-067-08677	FEDERAL 2-11 GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 11 34N 8W
WELL	05-067-09137	GEORGE GAS UNIT 11-11 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 11 34N 8W
WELL	05-067-07686	GEORGE 11-Nov	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 11 34N 8W
WELL	05-067-06337	XAVIER GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 11 34N 8W
WELL	05-067-08917	GEORGE GAS UNIT 11U-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 11 34N 8W

WELL	05-067-08916	MAYFIELD GAS UNIT 11U-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 11 34N 8W
WELL	05-067-06556	MAYFIELD 11 U-01 # 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 11 34N 8W
WELL	05-067-07538	FEDERAL 2-11 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 11 34N 8W
WELL	05-067-07156	TINKER FEDERAL GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 12 34N 8W
WELL	05-067-07124	DRY CREEK FEDERAL GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 12 34N 8W
WELL	05-067-08704	TINKER FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 12 34N 8W
WELL	05-067-08204	LORETT FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 13 34N 8W
WELL	05-067-09100	NEIL GAS UNIT 34-13 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 13 34N 8W
WELL	05-067-09054	NEIL GAS UNIT 34-13 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 13 34N 8W
WELL	05-067-07125	LORETT FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 13 34N 8W
WELL	05-067-07698	JEAN GAS UNIT 21-13 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 13 34N 8W

WELL	05-067-09157	JEAN GAS UNIT 21-13 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 13 34N 8W
WELL	05-067-09187	NEIL GAS UNIT 34-13 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 13 34N 8W
WELL	05-067-07778	NEIL 34-13	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 13 34N 8W
WELL	05-067-06701	MAYFIELD GAS UNIT 14U-1 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 14 34N 8W
WELL	05-067-08959	DICKENS GAS UNIT 44-14 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 14 34N 8W
WELL	05-067-09180	DICKENS GAS UNIT 44-14 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 14 34N 8W
WELL	05-067-07928	DICKENS 44-14 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 14 34N 8W
WELL	05-067-07792	FEDERAL 14-1 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 14 34N 8W
WELL	05-067-09031	MAYFIELD GAS UNIT 14U-01 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 14 34N 8W
WELL	05-067-07741	ANNALA FEDERAL GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 15 34N 8W
WELL	05-067-07259	A G SPARKS GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 15 34N 8W
WELL	05-067-08995	A.G. SPARKS GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 15 34N 8W

WELL	05-067-09114	A.G.SPARKS GAS UNIT 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 15 34N 8W
WELL	05-067-08958	MCCAW 34-15 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 15 34N 8W
WELL	05-067-08338	ANNALA FEDERAL GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 15 34N 8W
WELL	05-067-07687	MCCAW 34-15	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 15 34N 8W
WELL	05-067-06566	M W JOHNSON GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 16 34N 8W
WELL	05-067-08334	ROY ANNALA GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 16 34N 8W
WELL	05-067-07786	ROY ANNALA GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 16 34N 8W
WELL	05-067-08971	JONES GAS UNIT 34-16 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 16 34N 8W
WELL	05-067-07417	MW JOHNSON G A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 16 34N 8W
WELL	05-067-07694	JONES 34-16	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 16 34N 8W
WELL	05-067-07720	JAMES COLE GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 17 34N 8W
WELL	05-067-09268	LEMON GAS UNIT H 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 17 34N 8W

WELL	05-067-09267	LEMON GAS UNIT H 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 17 34N 8W
WELL	05-067-08346	LEMON GAS UNIT H 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 17 34N 8W
WELL	05-067-06561	LEMON 1-17U	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 17 34N 8W
WELL	05-067-09273	LEMON GAS UNIT J 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 17 34N 8W
WELL	05-067-09274	LEMON GAS UNIT J 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 17 34N 8W
WELL	05-067-08347	LEMON GAS UNIT J 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 17 34N 8W
WELL	05-067-06657	LEMON GAS UNIT J 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 17 34N 8W
WELL	05-067-08285	JAMES COLE GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 17 34N 8W
WELL	05-067-08701	REA GAS UNIT 18U-03 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 18 34N 8W
WELL	05-067-09098	LEMON G.U. K 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 18 34N 8W
WELL	05-067-06615	LEMON GAS UNIT K 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 18 34N 8W
WELL	05-067-08932	MORRIS,J.T.GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 18 34N 8W

WELL	05-067-07328	J-T MORRIS GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 18 34N 8W
WELL	05-067-06686	REA 18U-3 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 18 34N 8W
WELL	05-067-09189	REA GAS UNIT 18U-3 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 18 34N 8W
WELL	05-067-09190	REA GAS UNIT 18U-3 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 18 34N 8W
WELL	05-067-09101	LEMON G.U. K 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 18 34N 8W
WELL	05-067-08488	LEMON GAS UNIT K 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 18 34N 8W
WELL	05-067-06659	LUNT 19-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 19 34N 8W
WELL	05-067-08320	SOUTHERN UTE ALLOTTEE GU BC 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 19 34N 8W
WELL	05-067-08790	LUNT GAS UNIT 19-01 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 19 34N 8W
WELL	05-067-07317	SOUTHERN UTE ALLOTTEE GAS 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 19 34N 8W
WELL	05-067-06780	UTE 1A-20 NO. 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 20 34N 8W
WELL	05-067-06219	MCCAW UNIT 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 20 34N 8W

WELL	05-067-06619	UTE GAS UNIT 1A-20 NO.1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 20 34N 8W
WELL	05-067-06655	MCCAW 20-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 20 34N 8W
WELL	05-067-08883	KENNEDY GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 21 34N 8W
WELL	05-067-08910	LEROY MCCAW GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 21 34N 8W
WELL	05-067-07010	KENNEDY GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 21 34N 8W
WELL	05-067-07009	LEROY MCCAW GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 21 34N 8W
WELL	05-067-07705	BLACK 21-22	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 22 34N 8W
WELL	05-067-07779	MCMANUS 33-22	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 22 34N 8W
WELL	05-067-09018	BLACK GAS UNIT 21-22 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 22 34N 8W
WELL	05-067-08945	MCMANUS GAS UNIT 33-22 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 22 34N 8W
WELL	05-067-08215	TAYLOR GAS UNIT 21-23 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 23 34N 8W
WELL	05-067-07727	TAYLOR 21-23	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 23 34N 8W

WELL	05-067-07916	WITT 34-23	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 23 34N 8W
WELL	05-067-09300	COGBURN GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 24 34N 8W
WELL	05-067-09301	COGBURN GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 24 34N 8W
WELL	05-067-07851	COGBURN GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 24 34N 8W
WELL	05-067-07723	POWELL 22-26	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 26 34N 8W
WELL	05-067-07890	LAMKE GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 27 34N 8W
WELL	05-067-07713	KRAJACK 43-27	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 27 34N 8W
WELL	05-067-08954	LAMKE GS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 27 34N 8W
WELL	05-067-08835	KRAJACK GAS UNIT 43-27 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 27 34N 8W
WELL	05-067-07913	HJERMSTAD GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 28 34N 8W
WELL	05-067-08810	MCCAW GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 28 34N 8W
WELL	05-067-07373	MCCAW GAS UNIT "C" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 28 34N 8W

WELL	05-067-08843	HJERMSTAD GAS UNIT A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 28 34N 8W
WELL	05-067-06681	CREEK 29-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 29 34N 8W
WELL	05-067-07527	MCCAW GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 29 34N 8W
WELL	05-067-08407	CREEK GAS UNIT 29-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 29 34N 8W
WELL	05-067-08286	McCAW GAS UNIT D 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 29 34N 8W
WELL	05-067-07046	SOUTHERN UTE GAS UNIT DD 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 30 34N 8W
WELL	05-067-06974	BELLINO GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 30 34N 8W
WELL	05-067-08710	BELLINO GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 30 34N 8W
WELL	05-067-08832	SOUTHERN UTE TRIBAL FF 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 31 34N 8W
WELL	05-067-08757	SOUTHERN UTE TRIBAL EE 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 31 34N 8W
WELL	05-067-07229	SOUTHERN UTE TRIBAL FF 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 31 34N 8W
WELL	05-067-07047	SOUTHERN UTE TRIBAL EE 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 31 34N 8W

WELL	05-067-08780	REA,EARL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 32 34N 8W
WELL	05-067-09282	REA,RONALD GAS UNIT 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 32 34N 8W
WELL	05-067-06990	RONALD REA GAS UINIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 32 34N 8W
WELL	05-067-06989	EARL REA GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 32 34N 8W
WELL	05-067-08329	RONALD REA GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 32 34N 8W
WELL	05-067-09327	REA,RONALD GAS UNIT 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 32 34N 8W
WELL	05-067-07777	MOSKETTI 43-33	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 33 34N 8W
WELL	05-067-08859	MOSKETTI GU 43-33 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 33 34N 8W
WELL	05-067-08879	MABEL PAYNE GU 01-33 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 33 34N 8W
WELL	05-067-09226	PAYNE, MABEL 1-33 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 33 34N 8W
WELL	05-067-06551	PAYNE MABEL C Jan-33	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 33 34N 8W
WELL	05-067-07710	HRONICH 21-34	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 34 34N 8W

WELL	05-067-07896	KLUSMAN 33-34 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 34 34N 8W
WELL	05-067-08836	HRONICH GAS UNIT 21-34 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 34 34N 8W
WELL	05-067-09188	KLUSMAN GAS UNIT 33-34 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 34 34N 8W
WELL	05-067-08764	KLUSMAN GAS UNIT 33-34 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 34 34N 8W
WELL	05-067-07963	SOUTHERN UTE GAS UNIT VV 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 35 34N 8W
WELL	05-067-07944	SOUTHERN UTE GAS UNIT AE 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 35 34N 8W
WELL	05-067-06796	SOUTHERN UTE TRIBAL "A" 5	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 36 34N 8W
WELL	05-067-06710	#1M SOUTHERN UTE TRIBAL A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 36 34N 8W
WELL	05-067-06712	SOUTHERN UTE TRIBAL A 2-May	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 36 34N 8W
WELL	05-067-06832	SOUTHERN UTE TRIBAL A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 36 34N 8W
WELL	05-067-08494	HESTER GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 2 34N 9W
WELL	05-067-06960	HELEN CRAIG GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 9 34N 9W

WELL	05-067-08484	DUSTIN GAS UNIT 09-01 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 9 34N 9W
WELL	05-067-06651	DUSTIN 1-Sep	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 9 34N 9W
WELL	05-067-07379	EVERETT JONES GAS UT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 10 34N 9W
WELL	05-067-07424	WEBB REEDER GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 10 34N 9W
WELL	05-067-08750	JONES,EVERETT GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 10 34N 9W
WELL	05-067-08877	WEBB-REEDER GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 10 34N 9W
WELL	05-067-09276	LINDINER-SLATION GAS UNIT A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 10 34N 9W
WELL	05-067-07261	LINDER-SLATIN GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 10 34N 9W
WELL	05-067-09336	LINDNER-SLATIN GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 10 34N 9W
WELL	05-067-08950	LINDER-SLATIN GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 10 34N 9W
WELL	05-067-08875	COWAN, GRACE P. TRUST G.U,A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 11 34N 9W

WELL	05-067-08885	WEBB-REEDER GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 11 34N 9W
WELL	05-067-07874	WEBB-REEDER GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 11 34N 9W
WELL	05-067-06977	JONES GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 11 34N 9W
WELL	05-067-07039	HESTER GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 11 34N 9W
WELL	05-067-08672	JONES GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 11 34N 9W
WELL	05-067-07418	GRACE P COWEN TRUST GU A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 11 34N 9W
WELL	05-067-08733	LARSEN GS UNIT 1-12 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 12 34N 9W
WELL	05-067-08205	ALICE LORENZ GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 12 34N 9W
WELL	05-067-06767	LARSEN 12-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 12 34N 9W
WELL	05-067-08209	SOUTHERN UTE 12U-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 12 34N 9W
WELL	05-067-07855	POFF GAS UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 12 34N 9W
WELL	05-067-06951	ALICE LORENZ GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 12 34N 9W

WELL	05-067-06691	SOUTHERN UTE 12U-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 12 34N 9W
WELL	05-067-08414	FASSETT GAS UNIT 2-13 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 13 34N 9W
WELL	05-067-08413	HILL LELAND GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 13 34N 9W
WELL	05-067-06785	FASSETT 13-Feb	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 13 34N 9W
WELL	05-067-07570	LELAND HILL GAS UNIT 'A' 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 13 34N 9W
WELL	05-067-06981	CHAPMAN GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 14 34N 9W
WELL	05-067-08673	JOHNSON, V.K. GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 14 34N 9W
WELL	05-067-08842	CHAPMAN GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 14 34N 9W
WELL	05-067-07157	V-K JOHNSON GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 14 34N 9W
WELL	05-067-07423	SIMON SIMON LAND & CATTLE 15U-2R	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 15 34N 9W
WELL	05-067-08970	LINDNER GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 15 34N 9W
WELL	05-067-09270	LINDNER GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 15 34N 9W

WELL	05-067-08388	SIMON LAND AND CATTLE COM 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 15 34N 9W
WELL	05-067-07419	LINDNER GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 15 34N 9W
WELL	05-067-08342	CRAIG GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 16 34N 9W
WELL	05-067-08344	MCMAHON GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 16 34N 9W
WELL	05-067-06223	CRAIG UT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 16 34N 9W
WELL	05-067-06952	MCMAHAN GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 16 34N 9W
WELL	05-067-08708	HOTTER,JOE A.GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 17 34N 9W
WELL	05-067-08724	HOTTER GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 17 34N 9W
WELL	05-067-06964	JOE A HOTTER GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 17 34N 9W
WELL	05-067-07011	HOTTER GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 17 34N 9W
WELL	05-067-08411	CLARY GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 18 34N 9W
WELL	05-067-06959	CLARY GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 18 34N 9W

WELL	05-067-06968	WEASELSKIN GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 19 34N 9W
WELL	05-067-08399	RAY,BILLY 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 19 34N 9W
WELL	05-067-08422	WEASELSKIN GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 19 34N 9W
WELL	05-067-07274	BILLY RAY GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 19 34N 9W
WELL	05-067-06950	ARTHUR MASON GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 20 34N 9W
WELL	05-067-08403	MASON, ARTHUR GAS UNIT A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 20 34N 9W
WELL	05-067-08506	MASON ARTHUR GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 20 34N 9W
WELL	05-067-06849	MASON, ARTHUR GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 20 34N 9W
WELL	05-067-07420	SIMON 21U-1R 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 21 34N 9W
WELL	05-067-08364	GROFF GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 21 34N 9W
WELL	05-067-07040	GROFF GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 21 34N 9W

WELL	05-067-08379	SIMON LAND & CATTLE 21U-1R 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 21 34N 9W
WELL	05-067-08359	SIMON LAND & CATTLE COMPANY 1/22/2002	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 22 34N 9W
WELL	05-067-06953	SIMON LAND AND CATTLE CO 22-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 22 34N 9W
WELL	05-067-06994	ROGER D KELLEY GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 22 34N 9W
WELL	05-067-08360	KELLEY, ROGER D. GAS UNIT	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 22 34N 9W
WELL	05-067-08968	PICCOLI GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 23 34N 9W
WELL	05-067-09307	PICCOLI GAS UNIT A 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 23 34N 9W
WELL	05-067-09366	PICCOLI GAS UNIT A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 23 34N 9W
WELL	05-067-08965	LINDNER 23-1R	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 23 34N 9W
WELL	05-067-08966	LINDNER 23-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 23 34N 9W
WELL	05-067-07186	PICCOLI GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 23 34N 9W

WELL	05-067-07192	SOUTHERN UTE TRIBAL TT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 24 34N 9W
WELL	05-067-08727	SOUTHERN UTE TRIBAL,TT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 24 34N 9W
WELL	05-067-08424	FASSETT GAS UNIT 24-01 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 24 34N 9W
WELL	05-067-06601	FASSETT 24-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 24 34N 9W
WELL	05-067-08728	JEFFERIES GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 25 34N 9W
WELL	05-067-07421	JEFFERIES GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 25 34N 9W
WELL	05-067-06816	FEDERAL LAND BANK B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 25 34N 9W
WELL	05-067-08377	FEDERAL LAND BANK B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 25 34N 9W
WELL	05-067-09299	PICCOLI RANCHES GAS UNIT 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 26 34N 9W
WELL	05-067-08969	PICCOLI RANCHES GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 26 34N 9W
WELL	05-067-06954	PICCOLI RANCHES 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 26 34N 9W
		CUGNINI GAS UNIT A	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-08504	2	10000	PR	38300	NESW 26 34N 9W
WELL	05-067-06850	CUGNINI "A" GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 26 34N 9W
WELL	05-067-08871	WHITE,FRANCIS GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 27 34N 9W
WELL	05-067-06972	SIMON LAND & CATTLE CO 27-1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 27 34N 9W
WELL	05-067-06877	WHITE, F. GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 27 34N 9W
WELL	05-067-08840	SIMON LAND&CATTLE CO.NO27-1 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 27 34N 9W
WELL	05-067-08852	L.A. DAUGHETEE GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 28 34N 9W
WELL	05-067-07081	K CRAIG GAS UNIT 'A' 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 28 34N 9W
WELL	05-067-08922	K. CRAIG GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 28 34N 9W
WELL	05-067-06957	L A DAUGHETEE GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 28 34N 9W
WELL	05-067-08343	PHILLIPS GAS UNIT A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 33 34N 9W
WELL	05-067-06982	PHILLIPS GU A/PLA 6-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 33 34N 9W

WELL	05-067-08834	ZELLITTI GU A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 34 34N 9W
WELL	05-067-06840	ZELLITTI GAS UNIT 1A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 34 34N 9W
WELL	05-067-06841	TURNER SECURITIES GU A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 35 34N 9W
WELL	05-067-06817	FED. LAND BANK UNIT "A" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 35 34N 9W
WELL	05-067-09379	FEDERAL LAND BANK GU A 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 35 34N 9W
WELL	05-067-08331	TURNER SECURITIES GAS UNI 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 35 34N 9W
WELL	05-067-08333	FEDERAL LAND BANK A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 35 34N 9W
WELL	05-067-06818	FED. LAND BANK UNIT "C" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 36 34N 9W
WELL	05-067-06819	FEDERAL LAND BANK 'D' UT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 36 34N 9W
WELL	05-067-08262	FEDERAL LAND BANK D 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 36 34N 9W
WELL	05-067-08261	FEDERAL LAND BANK C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 36 34N 9W
		MAGOON GAS UNIT C	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-08376	1	10000	PR	38300	NESW 19 35N 6W
WELL	05-067-07400	MAGOON FEDERAL GU B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 19 35N 6W
WELL	05-067-08324	MAGOON GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 20 35N 6W
WELL	05-067-07151	FEINBERG GU B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 20 35N 6W
WELL	05-067-07414	MILLER GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 21 35N 6W
WELL	05-067-07887	SAULS CREEK GAS UNIT "B" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 27 35N 6W
WELL	05-067-07126	SAULS CREEK 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 27 35N 6W
WELL	05-067-07152	FEINBERG GU C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 28 35N 6W
WELL	05-067-08898	FEINBERG GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 28 35N 6W
WELL	05-067-07334	FEDERAL 28-01 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 28 35N 6W
WELL	05-067-07082	MAGOON FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 29 35N 6W
WELL	05-067-08326	MAGOON FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 29 35N 6W

WELL	05-067-08897	PAYNE EVELYN E 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 29 35N 6W
WELL	05-067-07012	EVELYN PAYNE E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 29 35N 6W
WELL	05-067-06903	PARRY LAND COMPANY B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 30 35N 6W
WELL	05-067-09077	DULIN GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 30 35N 6W
WELL	05-067-08325	PARRY LAND COMPANY GAS UN 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 30 35N 6W
WELL	05-067-07088	ROBERT DULIN GAS UNIT "C" 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 30 35N 6W
WELL	05-067-06904	EVELYN PAYNE C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 31 35N 6W
WELL	05-067-06948	EVELYN PAYNE GAS UNIT D 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 31 35N 6W
WELL	05-067-08961	PAYNE EVELYN D 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 31 35N 6W
WELL	05-067-06949	EVELYN PAYNE GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 31 35N 6W
WELL	05-067-07069	EVELYN PAYNE GAS UNIT F 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 32 35N 6W
WELL	05-067-08880	PAYNE,EVELYN GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 32 35N 6W

WELL	05-067-08881	PAYNE,EVELYN GAS UNIT F 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 32 35N 6W
WELL	05-067-06778	EVELYN PAYNE GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 32 35N 6W
WELL	05-067-07390	ALBRIGHT FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 33 35N 6W
WELL	05-067-08882	ALBRIGHT TRIMBLE GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 33 35N 6W
WELL	05-067-07245	ALBRIGHT-TRIMBLE GAS UT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 33 35N 6W
WELL	05-067-08332	ALBRIGHT FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 33 35N 6W
WELL	05-067-07030	SAULS CREEK 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 34 35N 6W
WELL	05-067-07127	SAULS CREEK 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 34 35N 6W
WELL	05-067-07159	STATE OF COLORADO AX 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 16 35N 7W
WELL	05-067-07205	LITTON FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 18 35N 7W
WELL	05-067-09079	LITTON FEDERAL G.U. 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 18 35N 7W

WELL	05-067-09080	WILBOURN FEDERAL G.U. 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENE 19 35N 7W
WELL	05-067-07233	WILBOURN FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 19 35N 7W
WELL	05-067-07174	CUNDIFF FEDERAL GU B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 19 35N 7W
WELL	05-067-08630	CUNDIFF FED. GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 20 35N 7W
WELL	05-067-07176	CUNDIFF GAS UNIT C 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 20 35N 7W
WELL	05-067-07175	CUNDIFF FEDERAL GU A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 20 35N 7W
WELL	05-067-08629	CUNDIFF GAS UNIT C 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 20 35N 7W
WELL	05-067-07070	REINSCH GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 21 35N 7W
WELL	05-067-09042	REINSCH GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 21 35N 7W
WELL	05-067-07234	LEWIS GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 21 35N 7W
WELL	05-067-07060	GOEGLEIN GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 22 35N 7W
WELL	05-067-08991	GOEGLEIN GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 22 35N 7W

WELL	05-067-06921	HUNTINGTON GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 22 35N 7W
WELL	05-067-06909	CONRAD GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 23 35N 7W
WELL	05-067-07194	WOMMER GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 24 35N 7W
WELL	05-067-08371	WOMMER GAS UNIT A 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 24 35N 7W
WELL	05-067-08348	DULIN, ROBERT GAS UNIT A	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 25 35N 7W
WELL	05-067-08355	DULIN, ROBERT GAS UNIT B	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 25 35N 7W
WELL	05-067-07075	ROBERT DULIN A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 25 35N 7W
WELL	05-067-07076	ROBERT DULIN GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 25 35N 7W
WELL	05-067-07296	DULIN, ROBER, GAS UNIT D	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 26 35N 7W
WELL	05-067-07177	BOWERS GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 26 35N 7W
WELL	05-067-08356	ROBERT DULIN GAS UNIT D 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 26 35N 7W
WELL	05-067-09010	BOWERS GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 26 35N 7W

WELL	05-067-07138	CONRAD RANCH GU B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 27 35N 7W
WELL	05-067-07195	STREETER GAS UNIT B 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 27 35N 7W
WELL	05-067-08357	STREETER GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 27 35N 7W
WELL	05-067-08362	CONRAD GAS UNIT B 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 27 35N 7W
WELL	05-067-07165	MONTGOMERY FEDERAL G U 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 28 35N 7W
WELL	05-067-07071	STREETER FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 28 35N 7W
WELL	05-067-08394	MONTGOMERY FEDERAL GU 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESW 28 35N 7W
WELL	05-067-08358	STREETER FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 28 35N 7W
WELL	05-067-07203	HANCOCK FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 29 35N 7W
WELL	05-067-08336	HANCOCK GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 29 35N 7W
WELL	05-067-07168	KLEIN FEDERAL GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 29 35N 7W

WELL	05-067-07148	WALLACE GULCH FEDERAL A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 30 35N 7W
WELL	05-067-07204	RICHARDSON FEDERAL GAS UT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 30 35N 7W
WELL	05-067-06558	GEARHART 31-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 31 35N 7W
WELL	05-067-06920	RICHARDSON GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 31 35N 7W
WELL	05-067-06944	GEARHART GAS UT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 31 35N 7W
WELL	05-067-08678	GEARHART 1 - 32 GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 32 35N 7W
WELL	05-067-08681	SMITH FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 32 35N 7W
WELL	05-067-07238	SMITH FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSE 32 35N 7W
WELL	05-067-06546	GEARHART Jan-32	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 32 35N 7W
WELL	05-067-07139	MILLER FEDERAL GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 33 35N 7W
WELL	05-067-07153	HUMISTON GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 33 35N 7W

WELL	05-067-08393	MILLER FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 33 35N 7W
WELL	05-067-08392	SOWER FEDERAL GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 34 35N 7W
WELL	05-067-09199	WOLTER,EMMETT GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 34 35N 7W
WELL	05-067-07141	EMMETT WALTER GU 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 34 35N 7W
WELL	05-067-07140	SOWER FEDERAL GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 34 35N 7W
WELL	05-067-07655	ISAAC TRUST GU A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 35 35N 7W
WELL	05-067-08999	DULIN ROBERT GAS UNIT 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 35 35N 7W
WELL	05-067-06962	ROBERT DULIN GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 35 35N 7W
WELL	05-067-07005	STATE OF COLORADO AW 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 36 35N 7W
WELL	05-067-07004	STATE OF COLORADO AW 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNW 36 35N 7W

WELL	05-067-08657	STATE OF COLORADO AW 4	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSW 36 35N 7W
WELL	05-067-08656	STATE OF COLORADO AW 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 36 35N 7W
WELL	05-067-07161	TYCKSEN GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 23 35N 8W
WELL	05-067-06507	RICHARDSON 25-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 25 35N 8W
WELL	05-067-07247	HARTMAN GAS UNIT 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NENW 27 35N 8W
WELL	05-067-07248	LOBATO GAS UNIT A 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SESE 28 35N 8W
WELL	05-067-06536	DAVIS 28-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNE 28 35N 8W
WELL	05-067-06571	STATE-CHASTAIN 31-Jan	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 31 35N 8W
WELL	05-067-06505	SHOEMAKER Jan-34	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 34 35N 8W
WELL	05-067-08664	SHOEMAKER GAS UNIT 1-34 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWSW 34 35N 8W
WELL	05-067-07754	RICHARDSON GU F 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESE 35 35N 8W
		RICHARDSON GU E	BP AMERICA PRODUCTION COMPANY		IGNACIO BLANCO	LA PLATA 067/34

WELL	05-067-06338	2	10000	PR	38300	NESW 35 35N 8W
WELL	05-067-09067	RICHARDSON G.U. F 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENE 35 35N 8W
WELL	05-067-07753	RICHARDSON GU E 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SWNW 35 35N 8W
WELL	05-067-09063	STATE OF COLORADO AV 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NESW 36 35N 8W
WELL	05-067-08323	STATE 1-36/35-8 3	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWNE 36 35N 8W
WELL	05-067-06945	STATE OF COLORADO AV 1	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 NWSE 36 35N 8W
WELL	05-067-07158	STATE 1-36/35-8 2	BP AMERICA PRODUCTION COMPANY 10000	PR	IGNACIO BLANCO 38300	LA PLATA 067/34 SENW 36 35N 8W

EXHIBIT 3

Russell, J. and A. Pollack, "Oil and Gas Emission Inventories for the Western States," Final Report prepared for Western Governor's Association (December 27, 2005)

Final Report

OIL AND GAS EMISSION INVENTORIES FOR THE WESTERN STATES

Prepared for

Western Governors' Association
1515 Cleveland Place, Suite 200
Denver, CO 80202

Prepared by

James Russell
Alison Pollack
ENVIRON International Corporation
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December 27, 2005

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PREFACE

Regulatory Framework for Tribal Visibility Implementation Plans

The Regional Haze Rule explicitly recognizes the authority of tribes to implement the provisions of the Rule, in accordance with principles of Federal Indian law, and as provided by the Clean Air Act (CAA) §301(d) and the Tribal Authority Rule (TAR) (40 CFR §§49.1–.11). Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.

2. Federally recognized tribes may apply for and receive delegation of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a Tribal Implementation Plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.

3. The Regional Haze Rule expressly provides that tribal visibility programs are "not dependent on the strategies selected by the state or states in which the tribe is located" (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12).

4. The EPA has indicated that under the TAR tribes are not required to submit §309 TIPs by the end of 2003; rather they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).

5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a Federal Implementation Plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a government to government basis in developing tribe-specific or generally applicable TIPs where necessary (See, e.g., 63 Fed. Reg.7263-64).

The amount of modification necessary will vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

Tribal Participation in the WRAP

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board.

Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred federally recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

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An adjunct study of oil and gas emissions point and area source emissions was conducted by ENVIRON and ERG. Oil and gas emissions for four tribes were inventoried: Wind River Reservation, Ute Mountain Ute Tribe, Navajo Nation, and Jicarilla Apache Nation. Emissions sources for the Jicarilla Apache Nation were inventoried, but they elected to not formally participate in the project. The final project report, *Point Source and Oil and Gas Area Source Emission Inventories on Native American Reservations and Tribal Lands* (ERG/ENVIRON, 2005), does not include Jicarilla Apache data.

1. INTRODUCTION

The oil and gas production industry considered in this study includes a large number of processes and equipment types that stretch from the wellhead to fuel distribution networks. Many of these processes emit significant quantities of nitrous oxides (NOx), volatile organic compounds (VOC) and other pollutants. Past emission inventories have estimated emissions from specific pieces of equipment, for limited geographic areas and for other segments of the industry. The largest oil and gas production facilities, gas plants and major compressor stations, have been previously inventoried as stationary sources. All states in the western region had previously compiled emission inventories for the year 2002 that included the major "point" emission sources in the oil and gas production industry. However, what was included in these emission inventories varied from state to state, depending on the permitting and/or reporting thresholds.

Oil and gas production facilities that are geographically distributed and have lesser emissions than the point source threshold are considered area sources. Prior to this study, there had not been a comprehensive emission inventory of oil and gas production operations in the western region that covered both point and area sources. Nor had there been a methodology developed to produce an inventory of this scope. The objective of the present study has thus been to develop and implement a uniform procedure for estimating area source emissions from oil and gas production operations across the western region. The emphasis of this study was placed on estimating emissions of pollutants with the potential to impair visibility near Class I areas in the west, in particular NOx emissions.

As this was the first effort to develop a regionally consistent emission inventory for oil and gas area sources, and resources were limited, this inventory is neither comprehensive nor as accurate as it might be with more resources. The focus was on the larger sources of NOx emissions; NOx and VOC emissions from minor wellhead processes for which emission factors were available were also estimated. This inventory and the methodology used should be considered as a first step toward a better understanding of oil and gas emissions, and the basis for further work to improve the estimates.

In developing the emission estimation methodology, considerable resources were devoted to incorporating the insights and guidance of a variety of stakeholders, as well as integrating the point source emissions estimates developed in previous inventory efforts. The work plans that guided this project were developed with substantial feedback from members of the WRAP Stationary Sources Joint Forum (SSJF) Oil and Gas Work Group.

The 2002 oil and gas point source emissions have been adopted from the state inventories (ERG, 2005a). The level of coverage in those inventories was evaluated and the point source emissions have been reconciled with emissions estimated using the newly developed area source inventory methodology.

Oil and gas point source emission inventories include location parameters. For the oil and gas area source emissions estimated in this project, a new spatial allocation scheme was developed to facilitate the integration of these emissions sources into the WRAP regional haze modeling. New spatial surrogates were developed for each of the non-point oil and gas emission sources addressed by this inventory. These surrogates, which are based on the geographic locations of

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The final task of this project was to formulate and implement a procedure to project the emissions from oil and gas production operations in 2018. For the WRAP 2018 base case modeling, only those emission control strategies that have already been adopted are considered. Once again, the work plan that guided the development of the projection method was developed in collaboration with the stakeholders represented in the SSJF Oil And Gas Work Group. Ultimately, oil and gas production forecasts were drawn from several sources and combined with the emissions estimates produced for the 2002 inventory and information on future controls to arrive at the 2018 inventory. Oil and gas point source projections are described in a separate report (ERG, 2005b).

This report describes the procedures developed in each task of this project and the results that have been obtained. Section 2 presents the methodology developed to create a comprehensive oil and gas emissions inventory for the western region and summarizes the emission inventory that was prepared for the year 2002. Section 3 then details the process used to create the spatial allocation surrogates that will appropriately assign oil and gas emissions to the locations where they occur. Section 4 describes the data sources and methods that have been used to project emissions in the year 2018, and provides the resulting emissions estimates.

2. 2002 BASE YEAR EMISSION INVENTORY

INTRODUCTION

This section describes the base year 2002 emission inventory of oil and gas area sources for the Western States. The focus of this inventory effort was to estimate emissions of nitrous oxides (NOx) from oil and gas production operations. In the early stages of this project, major NOx sources were identified and methodologies were defined for estimating emissions from those sources. The major NOx sources addressed by this inventory are: drill rigs, gas compressor engines, and coalbed methane pump engines. Emissions from minor NOx and VOC wellhead processes for which emission factors were available were also estimated.

Emissions for oil and gas point sources are also being provided by ENVIRON, but they are not addressed in this document beyond what is necessary to describe measures used to eliminate double counting. Also, the emissions summaries presented in this document do not include emissions classified as falling under tribal jurisdiction. ENVIRON has prepared separate emissions estimates of tribal oil and gas emissions for four tribes. Those emissions estimates are reconciled with the emissions reported here, and separate documentation of tribal emissions has been prepared (ERG/ENVIRON, 2005).

Apart from those western states that have no oil or gas production, such as Idaho and Washington, the only state for which area source emissions are not estimated is the State of California. The California Air Resources Board (CARB) has provided area source oil and gas emissions estimates directly to WRAP. Those estimates have been adopted into this inventory and are considered to be complete.

Table 2-1a presents a summary of NOx emissions from oil and gas area sources in the WRAP States. Table 2-1b presents a similar summary of VOC emissions. The area source emissions are distinguished by source category, except in California where only the total NOx emission from the ARB inventory is given. The point source emissions included in Tables 2-1a and 2-1b include several types of oil and gas facilities that are listed under SIC codes 13**, 492* or 4612 (ERG, 2005a). In most states, the major contributors of point source oil and gas emissions are natural gas transmission stations and natural gas processing plants. Crude oil pump stations and large storage sites also make a significant contribution in some states. Notably, the point source inventory methods in the State of Colorado and the State of Alaska are such that the majority of oil and gas emissions sources are included in the point source inventory.

Table 2-1a. 2002 State total NOx emissions (tons) from oil and gas sources.

State	Compressor Engines	Drill Rigs	Wellhead	CBM Pump Engines	Area Source Total	Point Source Total	TOTAL
Alaska		877	9		886	45,822	46,708
Arizona						2,735	2,735
California					8,070	16,707	24,777
Colorado		5,734	15,924	1,489	23,147	25,955	49,102
Idaho						2,590	2,590
Montana	2,027	1,044	4,721		7,792	4,275	12,067
Nevada	33	24	5		62	83	145
New Mexico	40,095	6,645	13,482	225	60,446	57,173	117,619
North Dakota	2,920	1,536	176		4,631	4,739	9,369
Oregon	73	-	12		85	1,182	1,267
South Dakota	284	36	47		367	323	690
Utah	2,371	676	2,143		5,190	3,311	8,500
Washington						1,281	1,281
Wyoming	7,025	4,964	6,283	1,428	19,699	15,015	34,715
Total	**54,828**	**21,536**	**42,800**	**3,141**	**130,376**	**181,191**	**311,566**

Note: Entries with a "-" indicate emissions were estimated to be zero. Entries that are blank indicate that emissions for the state/source combination are not estimated in this area source portion of the inventory.

Table 2-1b. 2002 State total VOC emissions (tons) from oil and gas area sources.

State	Oil Well, Tanks	Oil Well, Pneumatic Devices	Gas Well, Pneumatic Devices	Gas Well, Dehydrators	Gas Well, Completion - Flaring and Venting	Condensate Tanks - Uncontrolled	Condensate Tanks - Controlled	Area Source Total	Point Source Total	TOTAL
Alaska					430			430	2,310	2,740
Arizona									233	233
California								18,712	7,101	25,813
Colorado	785	137	3,388		21,075			25,386	63,960	89,346
Idaho									78	78
Montana	3,721	357	912		448	-	1	5,439	687	6,126
Nevada	121	7	1	0	-	-	-	129	23	152
New Mexico	10,671	1,484	2,893	40,509	33,884	77,333	-	166,773	11,527	178,300
North Dakota	6,572	329	22	601	172	-	43	7,740	187	7,926
Oregon	-	-	3	32	-	-	-	34	40	74
South Dakota	246	12	10	19	-	-	-	288	26	314
Utah	1,689	128	384	5,753	21,758	5,045	-	34,757	852	35,609
Washington									64	64
Wyoming	9,320	969	1,236	44,721	37,410	21,036	334	115,027	6,283	121,311
Total	**33,127**	**3,424**	**8,849**	**91,636**	**115,176**	**103,414**	**378**	**374,715**	**93,371**	**468,087**

Note: Entries with a "-" indicate emissions were estimated to be zero. Entries that are blank indicate that emissions for the state/source combination are not estimated in this area source portion of the inventory.

Table 2-2 compares the results of the present oil and gas inventory effort with the oil and gas emissions in the state inventories previously submitted to WRAP EDMS. Total NOx emissions estimated by this inventory of oil and gas emissions represent a 59 percent increase in inventoried oil and gas emissions. The increases in some of the main oil and gas producing states are even more dramatic. Emissions in Montana, North Dakota and Utah have increased by 182, 98 and 157 percent as a result of this effort. Oil and gas NOx emissions estimated for the State of New Mexico have increased by over 60,000 tons.

Table 2-2. Change in oil and gas NOx emissions in the 2002 inventory as a result of this inventory effort.

	WRAP Oil and Gas Inventory			Oil and Gas in Previous Inventory			Change in Oil and Gas Emissions	
State/Tribe	Area	Point	Total	Area	Point	Total	Total	Percent
Alaska	886	45,822	46,708		45,822	45,822	886	2%
Arizona		2,735	2,735		2,735	2,735	-	0%
California*	8,070	16,707	24,777	8,070	16,707	24,777	-	0%
Colorado	23,147	25,955	49,102		25,955	25,955	23,147	89%
Idaho		2,590	2,590		2,590	2,590	-	0%
Montana	7,792	4,275	12,067		4,275	4,275	7,792	182%
Nevada	62	83	145		83	83	62	75%
New Mexico	60,446	57,173	117,619		57,173	57,173	60,446	106%
North Dakota	4,631	4,739	9,369		4,739	4,739	4,631	98%
Oregon	85	1,182	1,267		1,182	1,182	85	7%
South Dakota	367	323	690		323	323	367	114%
Utah	5,190	3,311	8,500		3,311	3,311	5,190	157%
Washington		1,281	1,281		1,281	1,281	-	0%
Wyoming	19,699	15,015	34,715	6,409	15,015	21,424	13,290	62%
Total	**130,376**	**181,191**	**311,566**	**14,479**	**181,191**	**195,670**	**115,897**	**59%**

*Area source emissions in WRAP Oil and Gas Inventory adopted from data submitted by the California ARB.

MAJOR NOx SOURCE INVENTORY

Drilling Emission

The proposed approach for estimating emissions from drill rig engines was to use drill permit data from oil and gas commissions (OGCs) as a base measure of activity and to supplement that with more sophisticated data from drilling companies. This approach was then revised to replace the data from drilling companies with data from a survey of drilling in Southwest Wyoming. The final emission estimate uses several activity indicators from the drill permit data and combines that with emission factors derived from the Wyoming survey to make the most locally appropriate emission estimate.

In concordance with the proposed approach, we contacted large drilling companies to obtain data on the types of engines used for drilling, the normal operational schedule of the engines, regional variation of drilling rates and the relative activity of rotary versus workover rigs. The response to this survey was a mixture of refusal to participate and avoidance. Ultimately, none of the drilling companies contacted provided data to ENVIRON for this inventory effort.

Concurrent to the survey of drilling companies, we contacted State OGCs to obtain, amid other information, the activity data afforded by drill permits. The OGCs, in general, readily made the requested information available. The exception was the New Mexico Oil and Gas Conservation Commission, which declined to provide information. However, with considerable assistance from the New Mexico Air Quality Department, the necessary information was obtained for New Mexico as well. The drilling information obtained for each State is as follows:

- Spud date - the date that drilling commenced

- Well depth - the depth of the well; total vertical, measured or target depending on availability
- Completion date - the date well preparation is finalized; occurring with some delay after drilling ceases
- Well formation - the geologic structure that the well was drilled to
- Well field - the legal designation for the area where the well was drilled
- Well county - the county where the well was drilled; for allocation purposes

The completeness of this information varied considerably from State to State. While each State maintained a database containing these fields, every field was not completed for every well. The absence of this information required that some assumptions be made about the depth of some wells drilled and the duration of drilling. Those assumptions are documented later in this section. The references for the drill permit data are provided in Table 2-3.

Table 2-3. Source of drill permit data.

States with Drilling Activity in 2002	Source of Drill Permit Data
Alaska	Alaska Oil and Gas Conservation Commission (AK OGCC), 2005
Colorado	Colorado Oil and Gas Conservation Commission (CO OGCC), 2005
Montana	Montana Board of Oil and Gas Conservation (MT BOGC), 2005
North Dakota	North Dakota Industrial Commission, Oil and Gas Division (ND OGD), 2005
New Mexico	New Mexico Environmental Department (NM ED), 2005 and New Mexico Oil Conservation Division (NM OCD), 2004
Nevada	Nevada Division of Minerals (NV DM), 2005
South Dakota	South Dakota Department of Environment & Natural Resources, Minerals and Mining Program (SD MMP), 2005
Utah	Utah Division of Oil, Gas and Mining (UT DOGM), 2005
Wyoming	Wyoming Oil and Gas Conservation Commission (WY OGCC), 2005

The databases maintained by State OGCs provided the base level of activity to characterize the number of wells being drilled in an area, the depth of those wells and the amount of time required to construct the wells. What was still needed was the more detailed information about the drill rigs that the drilling companies did not provide. That information was necessary to tie this information about the characteristics of the well being drilled to emissions from drill rig engines. Fortunately, the Wyoming Department of Environmental Quality (DEQ) was able to provide results from a recent survey of drilling in the Jonah-Pinedale area of Southwest Wyoming.

The Jonah-Pinedale area has seen particularly intense drilling activity in recent years and the information provided represents the synthesis of emissions estimates made by ten different drilling companies for a total of 218 wells drilled. The emission factors derived from the

WYDEQ (2005) survey are 13.5 tons NOx per well and 3.3 tons SO_2 per well. The Colorado Department of Public Health and Environment (CDPHE) was also able to offer an emission factor. That factor was provided by only one company and without information available as to the area for which such a factor would be appropriate. Due to the larger survey size and the greater information available it was therefore the Jonah-Pinedale information that we used.

The emissions from the prime mover on a drill rig for drilling a well are dependent upon the depth of the well, the composition of substrate and the characteristics of the engine. For example, a small rig drilling a relatively shallow well in the Powder River Basin would have different emissions than a large rig drilling a deep well in the Jonah-Pinedale area. Because of this variation in drilling operations, it would not be appropriate to use the same Jonah-Pinedale emission factor for all wells drilled in the WRAP States without making some adjustments. To reflect this fact, we developed a methodology that uses information about the characteristics of wells in a specific area to scale the Jonah-Pinedale emission factor for drilling operations in that area.

The most specific unit for which well characteristics were commonly available was the formation. Creating formation-specific emission factors offers a good degree of accuracy because the well depths and substrate encountered when drilling the same formation should be consistent. To determine if the data supported that anticipated consistency, we did a simple statistical analysis of the drilling operations at several formations. This analysis showed that while there was variation of the elapsed time between spud date and completion date within one formation, the majority of wells drilled clustered near the average time for the formation. Figure 2-1 shows the distribution for the Blanco-Mesaverde formation in New Mexico. It shows that the large majority of wells drilled in that formation were drilled in a period that clustered around approximately 65 days. This consistency within a single formation would be irrelevant if it weren't for the absence of data for some wells. By the methodology developed, the emissions from the drilling of all wells in one formation are estimated using the average duration of well preparation activities and average well depth within the formation. This is based on the assumption that wells with no information for depth or duration will, on average, be well represented by all those wells in the formation for which depth and duration were available.

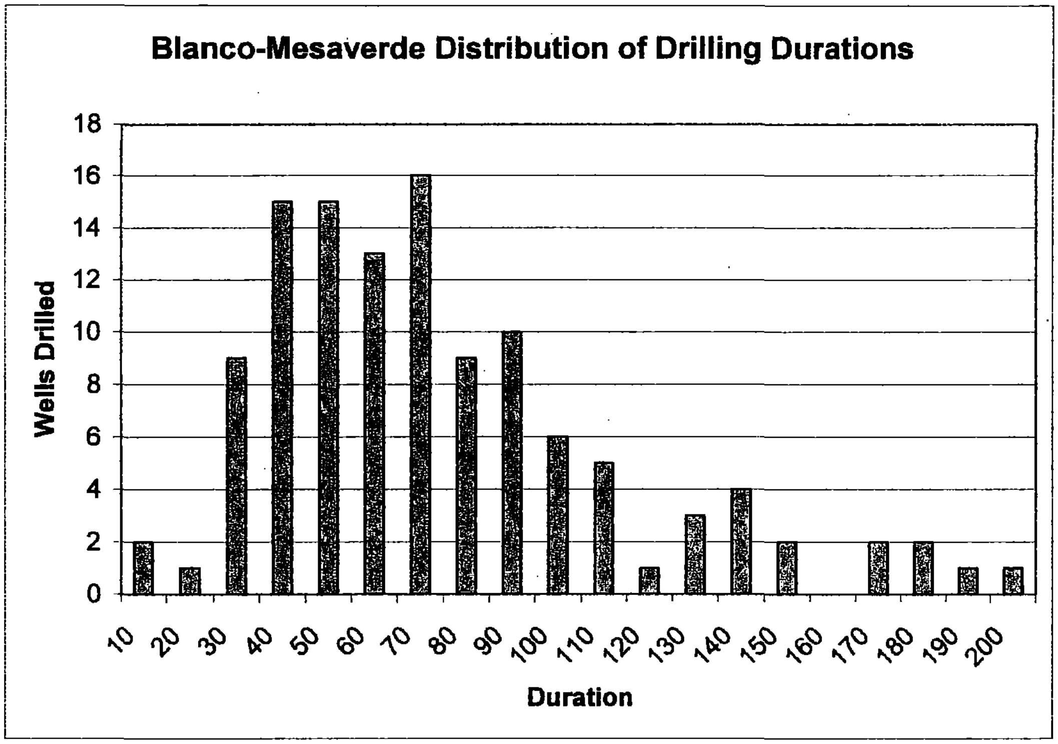


Figure 2-1. Distribution of well preparation activities within a single formation.

In addition to the assumption that the depth and duration of drilling activities for wells in a single formation are approximated by the average for the formation, two other important assumptions were made. First, it was necessary to assume that the difference between the completion date and the date that drilling ceased is, on average, constant relative to the total duration of preparation activities. This assumption was needed because the actual date that drilling ceased was not available. What this assumption means is that if on average wells with 100 days between spud date and completion actually had a duration of drilling of only 80 days, then on average wells with 50 days between spud date and completion would have 40 days of actual drilling. Though this is certainly not true on a well by well basis, it's assumed to be true for the formation averages used in this analysis.

It was also necessary to assume that the capacity of the equipment used to drill a well is dependent upon the depth of the well. This assumption was made because the data clearly indicated that substantially different rigs were employed in different drilling applications. Some wells in the Powder River Basin had the same approximate drilling duration as wells in Jonah-Pinedale. It was therefore assumed that the capacity of the prime mover would grow proportional to the depth of the well. With those two assumptions, it is then possible to scale the emission factor from the Jonah-Pinedale area to other formations based on the average well depth and drilling duration and in doing so to correct for variations due to well depth, composition of substrate, and engine capacity.

The first step in scaling the Jonah-Pinedale emission factor was to determine the appropriate average well depth and duration for the Jonah-Pinedale emission factor. The vast majority of wells drilled in Jonah-Pinedale were drilled to the Lance or Lance-Mesaverde formation. The average well depth and drilling duration for those formations - based on drill permit data obtained from the Wyoming OGC for 2002 and 2004 - was 11,896 ft and 80.6 days (WY OGCC

2005). The same type of average well depth and drilling duration was then calculated for the other formations drilled in 2002 in the WRAP States. A formation-specific emission factor was then created for each formation using Calculation 1.

Calculation 1:

$$EF_A = EF_J \times (D_A / D_J) \times (T_A / T_J)$$

where:

EF_A = *The emission factor for another formation*
EF_J = *The Jonah-Pinedale emission factor*
D_A = *The average depth of wells drilled in another area*
Dj = *The average depth of wells drilled in Jonah-Pinedale*
T_A = *The duration of drilling in another area*
T_j = *The duration of drilling in Jonah-Pinedale*

In some cases, lack of data did not permit the creation of a formation-specific emission factor. The situations where that occurred and the method used to surmount those obstacles are presented in Table 2-4.

Table 2-4. Situations where formation-specific emission factors could not be created.

Area	Problem	Solution
Wyoming	Some drilling records did not report the formation	Blank formation records were assigned to the most commonly drilled formation in the same field
South Dakota, Nevada	Not enough wells were drilled to justify a formation average	The state average depth and/or duration were used
New Mexico, North Dakota	No depths and/or durations were recorded for some formations	The state average depth and/or duration was used as a default
Montana	Formation was not available	Field averages were used

Additional adjustments were considered beyond those for well depths and durations. State DEQs were surveyed to determine if there were any control requirements for drill rigs. All State DEQs responded that controls were not required on drill rig engines. Based on that information, no adjustment for controls was necessary. It was, however, necessary to account for the varying fuel sulfur levels between different States and counties. This adjustment was actually made to the county-allocated SO2 emissions rather than to the emission factor. This was accomplished by multiplying the county SO2 emission by the ratio of that county's nonroad diesel sulfur level to the Wyoming nonroad diesel sulfur level. Fuel sulfur levels used in this adjustment are provided in Appendix C; these are the same fuel sulfur level developed for the WRAP 2002 nonroad diesel equipment emission inventory.

Emissions for a single formation were calculated using Calculation 2. The emissions for that formation were then allocated to the counties that intersected the formation based on the fraction of the total wells drilled that were drilled in each county's portion of the formation, as shown in Calculation 3.

Calculation 2:

$$E = EF \text{ x } W$$

where:

E = The 2002 emission for a given formation
EF = The formation specific emission factor
W = The number of wells drilled in the formation in 2002.

Calculation 3:

$$CE = E \text{ x } CW / TW$$

where:

CE = The 2002 emissions for a given county intersected by the formation
CW = The total number of wells drilled in the county's portion of the formation
TW = The total number of wells drilled in the formation

The state total drill rig NOx and SO_2 emissions that resulted from this procedure are shown in Table 2-5. The adjustments made to the emission factors are apparent in these results. While significantly more wells were drilled in the State of Wyoming than in New Mexico, the emissions in New Mexico are higher than in Wyoming. This occurs because many of the Wyoming wells were drilled quickly and to a shallow depth, as commonly occurs for the Powder River Basin CBM wells. In contrast, the wells in New Mexico were, on average, drilled deeper and took longer to drill. Where average drill depths and durations were more comparable, such as in Colorado and New Mexico, the emissions per well are relatively close. One piece of information requested from drilling companies that was not possible to obtain from other sources was the relative activity of rotary versus workover rigs. Some of the wells drilled represented here may be permits that were granted for a workover rig. Because workover rigs do not have the same constant, heavily loaded activity profile of rotary rigs, it is estimated that this represents a slightly conservative estimate.

Table 2-5. State total drill rig emissions.

State	Wells Drilled	NOx (tons)	SO2 (tons)
Alaska	205	877	48
Arizona			
Colorado	1,244	5,734	260
Idaho			
Montana	463	1,044	227
Nevada	6	24	1
New Mexico	932	6,645	1,444
North Dakota	157	1,536	358
Oregon			
South Dakota	7	36	8
Utah	126	676	147
Washington			
Wyoming	2,948	4,964	1,213
Total	6,088	21,536	3,706

Figure 2-2 presents a map of the 2002 drilling locations. Though not every well drilled is represented here because not all records included geographic coordinates, this map clearly displays the areas where well drilling activities were focused in 2002. This map also includes those wells that were drilled on tribal lands. The State emission totals presented in Table 2-4 should be considered accurate for the geographic area defined by the State boundaries, but not necessarily to the States' jurisdiction; a small amount of those emissions in the State inventory fall under tribal jurisdiction.

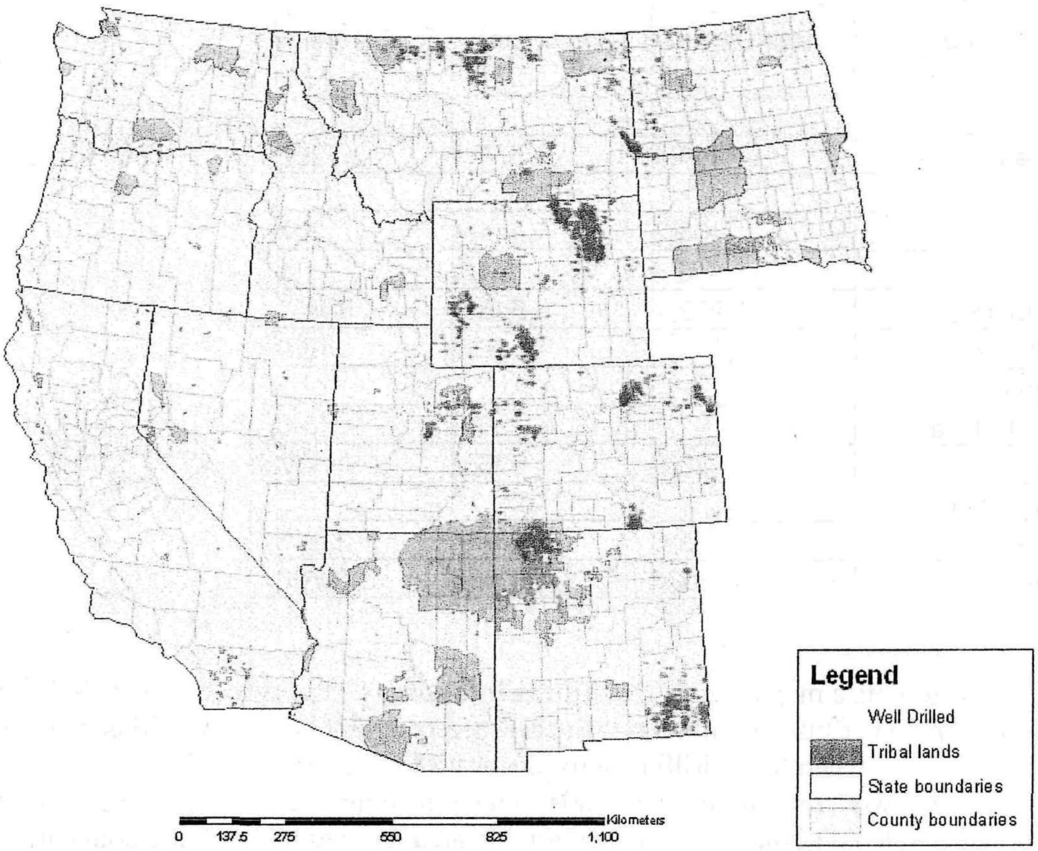


Figure 2-2. Wells drilled in 2002 in the WRAP states.

Non-Point Natural Gas Compressor Engine Emissions

For the purposes of this study, natural gas compressor engines have been grouped into three categories. The largest facilities, in terms of potential emissions, are the large natural gas compressor stations on natural gas transmission lines. These are typically Title V facilities and they are dealt with as point sources. The second tier of facilities is the gas gathering compressor station. In most States, these too have been included in a point source emission inventory. Some exceptions, where these medium sized facilities are not in the point source inventory and have thus been included in this area source inventory are discussed in section 2.3. The final category of compressor engines, which is the primary focus of this area source compressor engine emission estimate, is the group of relatively small, dispersed wellhead compressor engines. Figure 2-3 presents an example of such an engine. In all but two of the natural gas producing States, these engines have not been included in previous emission inventories and their inclusion here represents a significant advance in understanding this important component of the oil and gas production industry. The development of a methodology to address this emissions source, the application of that methodology and a summary of results are presented in this subsection.

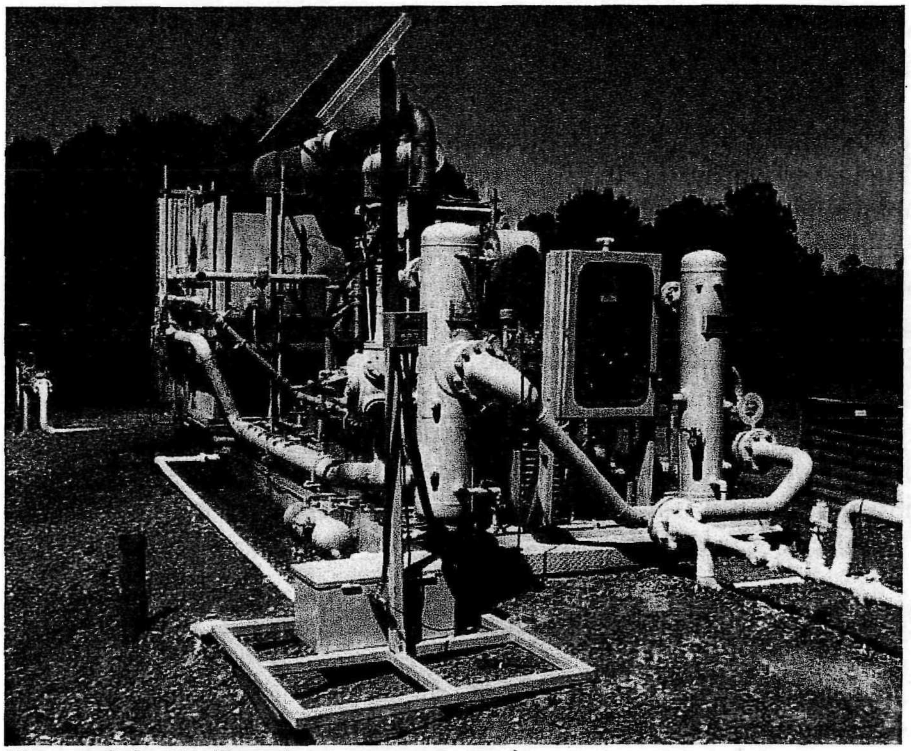


Figure 2-3. Wellhead compressor engine.

The preferred approach for estimating emissions from wellhead compressors that was described in the work plan focused on obtaining data from compressor operators. As was proposed, we contacted a large number of compressor operators, including exploration and production companies, gas gathering companies and compressor rental companies. This survey of operators was expected to produce, at a minimum, the number of wellhead compressors operated by each company. Also requested was information on compressor engine size, emissions data and operational schedule. Unfortunately, none of the companies contacted was willing to provide even a count of compressor engines. Repeated attempts were made to obtain data from the compressor operators, but ultimately it proved necessary to use an alternative methodology that did not rely on using data from operators.

The alternative methodology was to develop a production-based emission factor from local studies of compressor engine emissions. This emission factor was then combined with gas production data collected from the State OCGs to estimate emissions. Several local studies were analyzed to determine which offered the most appropriate data from which to derive the emission factor. The strengths and weaknesses of each of those studies and the ultimate selection of an industry-compiled inventory of wellhead compressor engines in the New Mexico portion of the San Juan Basin is discussed below.

<u>2002 Colorado Point Source Emission Inventory</u>

The Colorado Department of Public Health and Environment compiled a point source emission inventory for the year 2002 that includes sources with actual emissions down to 2 tons per year in attainment areas and 1 ton per year in non-attainment areas (CDPHE, 2005b). Given these exceptionally low inventory thresholds, all wellhead compressors are expected to have been included in the inventory. Gas production data was also obtained from the Colorado Oil and Gas Conservation Commission, making it appear possible to create a production-based emission factor by comparing emissions from the compressor engines in the Colorado point source inventory with gas production reported by the CO OGCC.

The extraction of only those engines used to power wellhead compressors from the point source inventory proved a more difficult task than expected. The coding of engines was such that it was difficult to distinguish between engines used for compression and engines used for other purposes such as pumping or generator sets. Nor was it possible to determine with confidence the subset of engines that represented only small wellhead compressor engines that would not be included in other States' point source inventories. This second problem represented an obstacle, because if medium-sized facilities were inadvertently included in the development of the emission factor then the resulting area source emission estimate for other States would be double-counting the emissions from medium-sized gas gathering facilities. Despite the fact that the CDPHE generously provided additional information from their records beyond what was provided in the point source inventory, it was not ultimately possible to develop an emission factor based on the Colorado point source inventory.

2002 New Mexico Oil and Gas Association's Inventory of Unpermitted Sources in the San Juan Basin

The New Mexico Oil and Gas Association (NMOGA) cooperated in the preparation of the Denver Early Action Compact by compiling an inventory for year 2002 of the unpermitted emissions sources operated by the oil and gas production industry in the New Mexico portion of the San Juan Basin. In the State of New Mexico, the threshold for permitting reported by the New Mexico Environmental Department was a potential to emit 25 tons per year (NM ED, 2005b). Thus, the inventory of unpermitted sources included those sources with a potential to emit less than 25 tons per year. The small wellhead compressor engines fall into this category. The NMOGA inventory provided emissions for wellhead compressor engines, which could be compared to production statistics for the San Juan Basin to derive an emission factor with units of tons NOx per MCF of gas produced.

The NMOGA inventory was based on a survey of exploration and production companies. The survey obtained responses representing activity at 10,582 of 17,108 wells. Emissions for wellhead compressor engines submitted by the responding companies totaled 14,892 tons NOx (NMOGA, 2003). To estimate the emissions at all wells, this emission was divided by the fraction of wells represented in the responses. This produced an estimate of 24,076 tons of NOx emitted by wellhead compression in the New Mexico portion of the San Juan Basin.

This emission estimate corresponds to gas production in three New Mexico counties: Rio Arriba, San Juan and Sandoval. Total 2002 gas production for those three counties was obtained from the on-line production database maintained by the New Mexico Institute of Mining and Technology. Production figures are summarized in Table 2-6.

Table 2-6. 2002 gas production in the San Juan Basin – New Mexico.

County	2002 Gas Production (MCF)
Rio Arriba	391,007,587
San Juan	638,024,961
Sandoval	1,420,527
San Juan Basin Total	**1,030,453,075**

(NMT, 2005)

With these estimates of total gas production and total emissions for wellhead compression, it was possible to calculate a production based emission factor as the quotient of total emissions divided by total gas production. The result is an emission factor of $2.3x10^{-5}$ tons NOx per MCF gas produced.

Bureau of Land Management Environmental Impact Statements

Several Bureau of Land Management (BLM) environmental impact statements (EIS) were examined for information they might provide on the relationship of gas compression and gas production. The Powder River Basin EIS included the most complete information on the anticipated compression needs for the future development of gas wells. That information, in the form of expected installed wellhead compression capacity, was combined with an EPA emission factor for natural gas fired engines, to estimate the expected emissions from natural gas fired engines. This estimate was then compared to the estimated gas production to develop a production-based emission factor.

The Powder River Basin EIS estimated that 380 horsepower of installed compression capacity would be required for every 250 MCF-day of new gas production (BLM, 2002). Assuming 8,760 hours per year of gas production and hence compressor operation, this equates to 3,328,800 horsepower-hours per year for 91,250 MCF of gas production. Applying the 12 grams NOx/hp-hr emission factor for Light Commercial Gas Compressors (SCC2268006020) from the EPA's NONROAD2004 emissions model, this compressor activity would result in 44 tons of NOx. Dividing this result by the associated production, 91,250 MCF, results in a production-based emission factor of $4.8x10^{-4}$ tons NOx per MCF.

The emission factor derived from the BLM EIS is based on the fundamental assumption that 380 horsepower of compression will be added for every 250 MCF-day of gas production. Supporting evidence for this assumption is not provided in the Powder River Basin EIS. The EIS is a forecast of production and equipment that may be installed, not a study of existing operations. Although it provides sufficient information to calculate the necessary production-based emission factor, these limitations would not allow us to place a high degree of confidence in the estimates produced by that emission factor.

East Texas 2002 Emission Inventory

The emission inventory prepared for the Tyler/Longview/Marshal Flexible Attainment Region of East Texas included an estimate of the emissions for area source compressor engines. The method used by the contractor, Pollution Solutions (2005), to estimate gas compressor emissions was to develop a relationship between compressor engine activity and gas production from a survey of compressor operators. That relationship was then used with gas production statistics and EPA emission factors to estimate engine emissions.

The survey of operators yielded a relationship of 191 horsepower of compression per MMSCF-day of gas production. Assuming 8760 hours per year of operation, as was done in the East Texas Inventory, this results in 1,673,160 hp-hr/year per MMSCF-day. Converting that figure to an activity factor based on annual gas production gives 4,584 hp-hr per MMSCF or 4.58 hp-hr per MSCF. Combining that with the 11 g NOx/hp-hr emission factor used by Pollution Solutions results in a production-based emission factor of $5.6x10^{-5}$ tons NOx per MCF.

The emission factor derived from the results of the East Texas survey seemed a good candidate for use in the present study. It was derived from actual operations and falls between the factors derived from the NMOGA inventory and the BLM EIS. However, Pollution Solutions was unwilling to provide the details of the survey that resulted in the emission factor used in the East Texas work. Without supporting documentation and technical basis we could not use the resulting emission factor.

Compressor Engine Emission Estimate

The results of the review of compressor engine studies are summarized in Table 2-7. The attempt to derive an emission factor from the Colorado 2002 Point Source Inventory was unsuccessful. The use of BLM EIS was ruled out due to the speculative nature of the production-compression relationship used in that study. Nor did it seem possible to use the emission factor derived from the East Texas Inventory in the absence of supporting evidence. We therefore decided to use the emission factor derived from the New Mexico Oil and Gas Association's Inventory of Unpermitted Sources in the San Juan Basin. This study has several advantages over the other studies. It is a study of existing operations in an important production area of the WRAP States and the survey of compressor operators attained a very high response rate. With a production-based emission factor of 2.3×10^{-5} tons NOx per MCF of gas production, it was then possible to estimate emissions based on gas production statistics obtained from the oil and gas commissions.

Table 2-7. Summarized results of review of compressor engine studies.

Source	Emission Factor (tons NOx / MCF)	Advantages	Disadvantages
CO Inventory	Inconclusive		
NMOGA Inventory	2.3x10-5	• Very good coverage/response • Important WRAP production area	
BLM Powder River EIS	4.4x10-4	• Important area of growth	• Projected, not actual equipment and production
East Texas EI	5.6x10-5	• Based on survey data • Resulting EF falls between NMOGA and BLM factors	• Lack of supporting evidence

We had previously requested from the OGCs well-specific oil and gas production statistics. These were obtained, either submitted by the OGC or downloaded from the on-line production statistics maintained by some States OGCs, for all oil and gas producing States. For the compressor engine emissions estimate, total 2002 natural gas production was summed for each county and county level emissions were estimated as the product of natural gas production (MCF) and the production-based emission factor.

The only States that reported requiring controls on compressor engines were Utah and Wyoming. In both of those States, the emissions are controlled to a rate of 1-2 grams NOx /hp-hr (WY DEQ, 2005c; UT DEQ, 2005). This represents a substantial reduction from the average emission rate of 11.4 grams NOx/hp-hr that was found by the NMOGA Inventory. The production-based emission factors for Utah and Wyoming have been adjusted downward to account for this difference. In both States, the controlled emission factor was calculated as the product of the uncontrolled emission factor, $2.3x10^{-5}$ ton NOx/MCF, and the ratio of controlled hourly emissions to uncontrolled hourly emissions, 2 grams NOx/hp-hr to 11.4 grams NOx/hp-hr. A summary of compressor engine controls reported by State agencies and the control-adjusted emission factors are presented in Table 2-8.

Table 2-8. *State controls on compressor engines and controlled emission factors.*

State	Reference	Control Requirement	Emission Factor (ton NOx/MCF)
Alaska	AK DEC, 2005b	NA[1]	
Colorado	CDPHE, 2005b	NA[1]	
Montana	MT DEQ, 2005	None	$2.3x10^{-5}$
New Mexico	NM ED, 2005b	None	$2.3x10^{-5}$
Nevada	NV DEP, 2005	None	$2.3x10^{-5}$
North Dakota	ND DH, 2005	None	$2.3x10^{-5}$
South Dakota	NV DENR, 2005	None	$2.3x10^{-5}$
Oregon	OR DEQ, 2005	None	$2.3x10^{-5}$
Utah	UT DEQ, 2005	Controlled to 1-2 g NOx/hp-hr	$4.1x10^{-6}$
Wyoming	WY DEQ, 2005c	Controlled to 1-2 g NOx/hp-hr	$4.1x10^{-6}$

[1] Any controls required on compressor engines are included in the point source inventory.

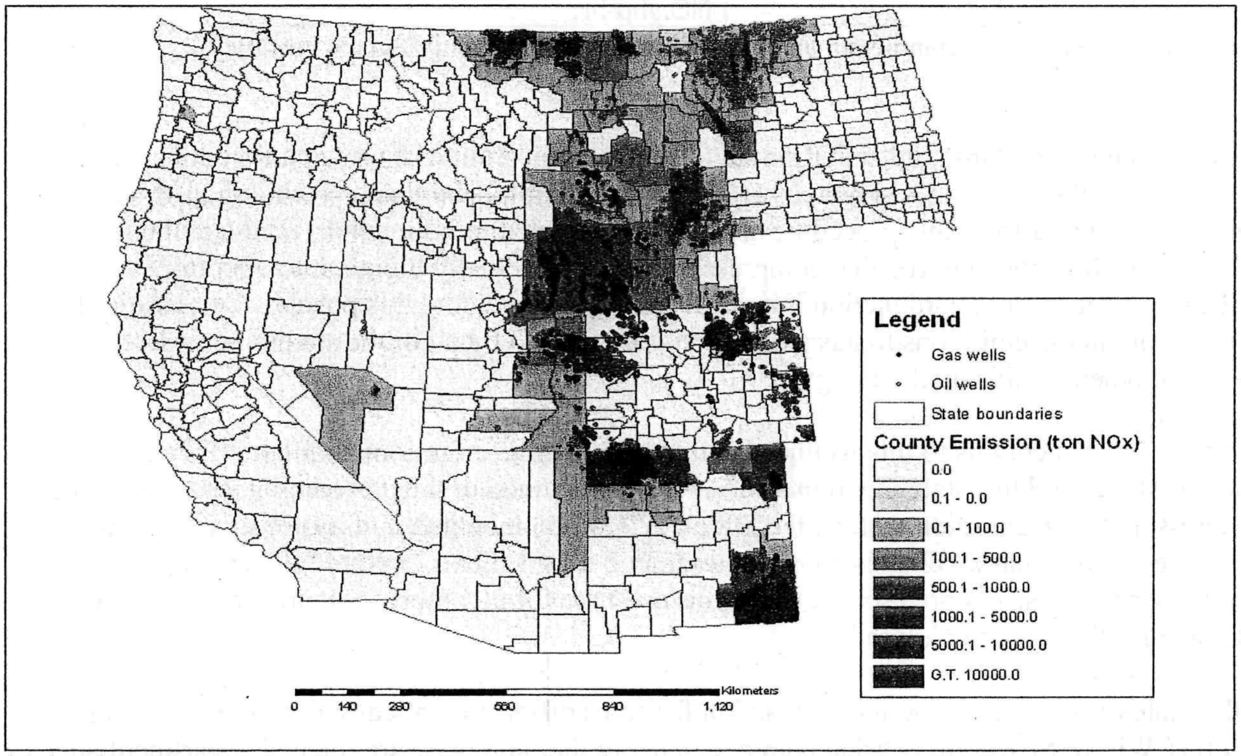
The State total NOx emissions that resulted from the application of these emission factors are presented in Table 2-9. As is shown in Table 2-9, and graphically displayed in Figure 2-4, emissions resulting from this procedure are directly related to production. Though at the level of individual wells it may be true that compressor activity is actually higher at less productive wells, when county level production is considered, as in this study, this positive correlation of compressor engine emissions to gas production is supported by all of the studies considered in the development of this methodology.

There are two exceptions to this wellhead compressor engine emissions estimate. Those are the State of Alaska and the State of Colorado. As was mentioned in the preceding discussion of the compressor engine emission factors, the State of Colorado included in its point source inventory all sources with actual 2002 emissions greater than 2 tons. This is expected to include all compressor engines. An area source emissions estimate for compressor engines was therefore not made for the State of Colorado.

In the State of Alaska, oil and gas production facilities differ dramatically from those found in the other WRAP States. In Alaska, both personnel in the State's environmental department and the oil and gas conservation commission indicated that facilities are arranged in a 'wagon wheel'. At the hub of the facility is the large processing plant, and each spoke reaches out to the production wells. Along the spokes and at the wellhead, there is emissions-producing equipment. However, this equipment is permitted along with the processing plant (AK OGCC, 2005b; AK DEC, 2005b). Wellhead compressor engines would therefore be included along with the equipment in the processing plant as a point source in the 2002 Alaska point source emissions inventory. For that reason, area source compressor engine emissions are not made for the State of Alaska.

Table 2-9. State total NOx emissions from gas compressor engines.

State	Total Gas Produced (MCF)	Emission Factor (tons NOx/MCF)	Total 2002 NOx Emission (tons)
Alaska	3,496,429,130	NA	
Arizona	-		
Colorado	1,241,311,742	NA	
Idaho	-		
Montana	86,761,832	2.30E-05	2,027
Nevada	6,433	2.30E-05	0
New Mexico	1,716,107,712	2.30E-05	40,095
North Dakota	59,979,925	2.30E-05	1,401
Oregon	837,067	2.30E-05	20
South Dakota	10,955,008	2.30E-05	256
Utah	283,408,406	4.10E-06	1,182
Washington	-		
Wyoming	1,708,567,844	4.10E-06	7,024
Total	8,604,365,099		54,827



*Colorado wellhead compressor emissions are in the point source inventory
**California ARB has provided separate estimates of area source oil and gas emissions

Figure 2-4. County-level 2002 gas compressor engine emissions.

Medium-Sized Facilities

The emission factor developed for the wellhead compression estimate was directed at estimating emissions from sources with a potential to emit less than 25 tons per year. This was the type of source considered by the NMOGA inventory. This proved convenient, as in many States, sources with a potential to emit greater than 25 tons per year were reported by the State DEQ to be included in the point source emission inventory. However, this was not the case in all States. A summary of the State inventory thresholds is presented in Table 2-10.

Table 2-10. State point source inventory thresholds.

State	Point Source Inventory Threshold	Reconciliation	Source
Alaska	PTE 100 TPY	Smaller wellhead equipment reported to be grouped under these large facilities	AK DEC, 2005b
Arizona	PTE 40 TPY	Determined that all medium sized facilities exceeded PTE 40 TPY	AZ DEQ, 2005
Colorado	2 TPY actual emissions	Removed compressor, condensate tank and glycol dehydrator emissions from area source inventory	CDPHE, 2005b
Montana	PTE 25 TPY		MT DEQ, 2005
New Mexico	PTE 25 TPY		NM ED, 2005b
North Dakota	PTE 100 TPY	Used State's internal inventory of compressor stations to include sources with a PTE between 25 and 100 TPY	ND DH, 2005
Nevada	PTE 5 TPY	No wellhead compressor engines included in State's inventory. No reconciliation required	NV DEP, 2005
Oregon	PTE 100 TPY	Obtained inventory of compressor stations with PTE less than 100 TPY from State	OR DEQ, 2005
South Dakota	PTE 100 TPY	Created scaling factor based on NM point inventory and gas production	SD DENR, 2005
Utah	PTE 100 TPY	Created scaling factor based on NM point inventory and gas production	UT DEQ, 2005
Wyoming	PTE 25 TPY		WY DEQ, 2005c

As shown in Table 2-10, Montana, New Mexico and Wyoming all included sources with a potential to emit 25 tons per year or greater in their point source inventories. The State of Alaska and the State of Colorado have different inventory thresholds, but this did not require any reconciliation of the area source compression emission estimate as in those States wellhead compression is included entirely in the point source emission inventory.

In Arizona, Nevada, Oregon and North Dakota, Utah and South Dakota, the fact that the States' inventory thresholds differed from the New Mexico PTE 25 tpy threshold required special treatment. Discussion with staff at the Arizona and Nevada DEQ revealed that despite the different thresholds, no further action was necessary. In Arizona, there were no compressor facilities with a potential to emit between 25 tpy and 40 tpy (AZ DEQ, 2005). In Nevada, despite the relatively low inventory threshold, no wellhead compressor engines had been included in the point source inventory (NV DEP, 2005).

In Oregon and North Dakota, State DEQ personnel indicated that there were oil and gas facilities that fell below the State point source inventory threshold, but were larger facilities that would not be accounted for in the area source wellhead compression estimate. Despite their exclusion from the point source inventory, both Oregon and North Dakota did have internal emissions estimates for these medium-sized facilities. Those emissions data were obtained from the State and have been included in the area source emission inventory (see Table 2-13).

In Utah and South Dakota, there existed the same gap between the wellhead compression emissions and the state point source inventory as in Oregon and North Dakota. However, in Utah and South Dakota it was not possible to obtain emissions data from the State agencies. It was therefore necessary to estimate emissions for this group of facilities based on the gas production in those States. This was done by selecting the subset of point source facilities from the New Mexico point source inventory that had a potential to emit between 25 and 100 tons per year, relating those facilities to New Mexico gas production and then scaling the emissions from those facilities to gas production in Utah and South Dakota.

The facilities in New Mexico with a potential to emit between 25 and 100 tons per year were identified by first extracting only facilities coded with an oil and gas SIC; the SIC used are listed in Table 2-11. The next step was to calculate the potential to emit for each emission unit included in those oil and gas facilities. This was accomplished by scaling the emissions reported for the unit up to what they would be if the unit had been operated 8760 hours per year. For example, if a unit in the inventory had emissions of 10 tons NOx, but had only operated 4000 hours, then the potential to emit for that unit was calculated as the product of 10 tons NOx and 8760/4000. In this case the potential to emit would then be 21.9 tons NOx. Though we acknowledge that factors other than the total hours of operation may be used in the determination of potential to emit, the detailed determination of potential to emit for each emission unit was not possible given the available resources. After estimating the potential to emit as described for each emission unit, the facility total PTE was then calculated by summing the PTE of all units in that facility. Those facilities with a total PTE under 100 tpy were extracted.

Table 2-11. Oil and gas SIC.

SIC	Description
1311	Crude Petroleum and Natural Gas
1321	Natural Gas Liquids
1382	Oil and Gas Field Exploration Services
1389	Oil and Gas Field Exploration Services, NEC
4612	Crude Petroleum Pipelines
4922	Natural Gas Transmission
4923	Natural Gas Transmission and Distribution
4925	Mixed, Manufactured or Liquefied Petroleum Gas Production

Using the information in the New Mexico inventory, it was possible to separate the facilities with a PTE between 25 tons per year and 100 tons per year into two categories: gas compression and gas processing. The total emissions in each of these categories were then summed to determine the State total emissions. By dividing those totals by the State total gas production we arrived at the production-based emission factors shown in Table 2-12.

Table 2-12. Emissions for New Mexico natural gas facilities with a PTE between 25 and 100 tpy.

Type of Facility	Gas Processing	Gas Transmission
Total Emissions (tons NOx)	2,715	4,195
Total Gas Production (MCF)	1,624,225,738	
Emission Factor (ton NOx/MCF)	1.67×10^{-6}	2.58×10^{-6}

Combining the emission factors in Table 2-12 with the county gas production in Utah and South Dakota, we estimated emissions for the medium-sized gas processing and transmission facilities in those states. Using these emissions estimates and the emissions provided by State agencies for Oregon and North Dakota, we have supplemented the area source emissions estimates for those States to include the facilities with a potential to emit between 25 and 100 tons per year. Also included in this supplement is a compression facility in Clark County, Nevada. Although no action was required to reconcile the inventory prepared by the State of Nevada, Clark County submitted its own inventory in which it grouped a compressor facility in with other sources of natural gas combustion. We obtained emissions for this source and have included it in the oil and gas area source emission inventory. The State total emissions for these facilities are shown in Table 2-13.

Table 2-13. Area source emissions estimate for facilities with a PTE between 25 and 100 tpy.

State	Medium Facility Emissions (tons NOx)	Source
Oregon	53.8	OR DEQ, 2005
North Dakota	1,518.4	ND DH, 2005
Utah	1,222.6	Estimated
South Dakota	28.3	Estimated
Nevada	33	CC DAQM, 2005

Coal Bed Methane Generators

The methodology described in the work plan for estimating emissions from coal bed methane generators relied on obtaining information on generator specifications and usage from State environmental departments. Based on the map of CBM production obtained from the Energy Information Administration (Figure 2-5), environmental departments were contacted for this information in five States: Colorado, Montana, New Mexico, Utah and Wyoming. Of those, only Wyoming was able to provide information on the generators associated with CBM wells (WYDEQ, 2004; WYDEQ, 2005b). Contacts in Montana and Utah indicated that the CBM fields in their states are electrified and pumps are expected to be operated on line power (Richmond, 2005; Daniels, 2005). Therefore it remained to determine generator usage in only Colorado and New Mexico.

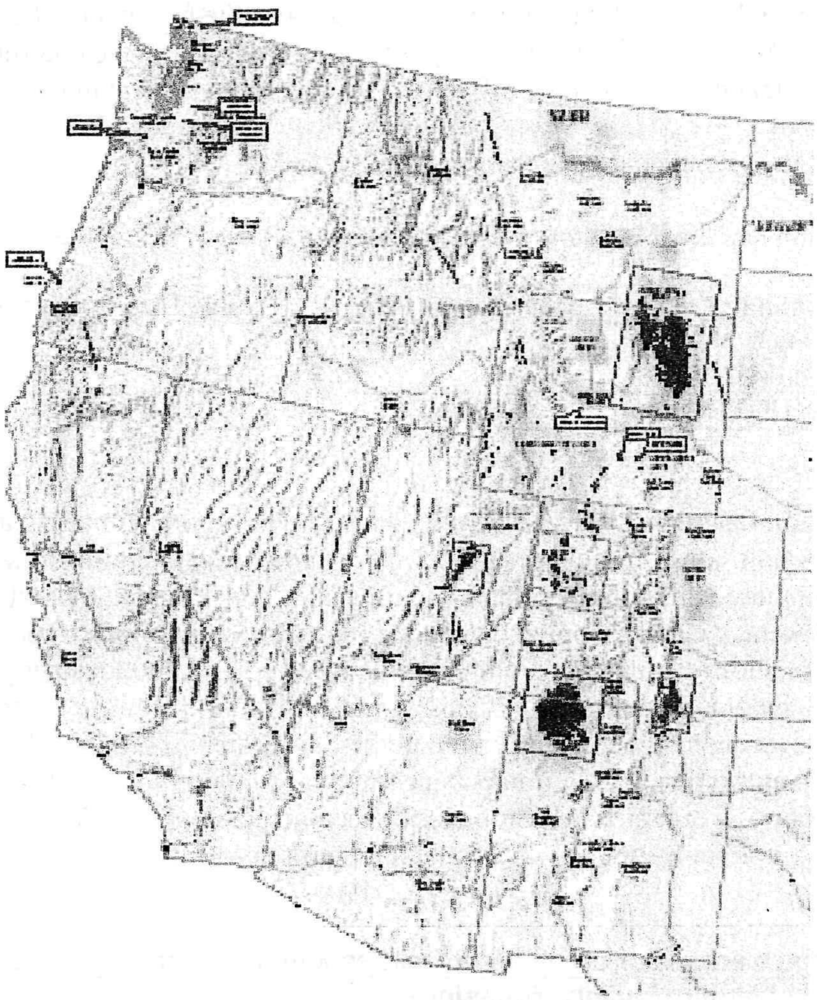


Figure 2-5. Western U.S. Coal bed methane fields (EIA, 2004).

While contacting the State environmental departments to obtain data on generators, we also requested production data from OGCs in each of the WRAP States. In the States with CBM production, that data included the water production at CBM wells. In addition, the depth of wells was obtained for some sampling of the wells in each State; depth information was not available for every well. Based on the data available, the first emission estimate that we produced was the result of scaling the generator activity obtained for the State of Wyoming to the other CBM producing states based on the average depth of wells and the water produced at CBM wells. This scaling was made based on the understanding that the work performed by generators is correlated to the mass of water lifted by pumps and the distance over which it must be lifted.

The emissions produced by this first methodology did not appear sufficient to represent the activity at the large number of CBM wells in Colorado, New Mexico and Wyoming. The emissions determined by this method, on a per well basis, for these three States were 0.080, 0.010 and 0.067 tons NOx respectively. One possible explanation for the surprisingly low results determined by this method is that the generator information obtained from the State of Wyoming excluded some of the engines, possibly those that are directly coupled to CBM pumps. Also, actual hours of operation were only available for a subset of the generators. Activity of the remaining generators in Wyoming was extrapolated from the activity of that subset. It's possible that the activity of the subset was not representative of the entire population of generators. In summary, engineering calculations showed that a great deal more work would be performed in dewatering CBM wells than was suggested by this emissions estimate based on the WYDEQ emissions factors.

Operating under the assumption that the database of generators obtained from the Wyoming DEQ may not include all the engines associated with dewatering, it was necessary to develop an emissions estimation methodology where activity could be determined based only on the well production data obtained from the State OGC. Information on the design and operation of CBM wells in combination with engineering calculations provided a way to estimate engine activity (horsepower-hours) based on water production. Once horsepower-hours were estimated, it was then possible to derive an emission estimate using an emission factor from EPA's NONROAD2004 emissions model.

Estimating Engine Activity

Engine activity was determined for each well by first determining the water power developed by the dewatering pump. Using an assumption of the pump's efficiency it was then possible to determine the power that must be supplied to the pump. Assuming that losses in the electrical delivery system are negligible, the power supplied to the pump is the same as the power produced by the generator. Then, by estimating the efficiency of the generator system at converting the power at the engine flywheel to electrical power it was possible to estimate the horsepower-hours of the engine. This was then combined with an emission factor to determine emissions resulting from the dewatering of each well. The complete list of assumptions used for this calculation are presented in Table 2-14.

Table 2-14. Assumptions used in developing the CBM generator emissions estimate.

Assumption	Reason
Pumping in NM and CO is done by natural gas fired engines. Pumping in WY is done with a mix of natural gas and diesel engines.	The Wyoming generator data shows that the majority of the generator horsepower is natural gas fired (WY OGCC, 2005b). Also, industry representatives indicate that use of electric power from the grid is minimal (Gantner, 2005).
Pump efficiency = 0.6	Industry provided estimate (Olson, 2004).
Generator efficiency = 0.85	Estimate based on small size of engines.
Downhole pressure contribution is negligible	Simplification necessary due to lack of data. This leads to a slightly conservative estimate.
Power delivered the pump is exactly equal to the power required to lift water over the depth of the well and overcome frictional losses. Minor losses (joints, flanges, etc...) and exit velocity are assumed to be negligible	The power in lifting the water is undoubtedly much greater than any of the other components. No data available on minor losses and exit velocity.
Diameter of pipe that conducts water to surface is 0.2 ft	Wyoming OGC provided estimate (Strong, 2005)
Pipe roughness of drawn/plastic tubing (5x10-6 ft)	Industry contact stated majority of piping is fiberglass (Weatherford, 2005)
8760 hours of engine operation and 4380 hours of pumping per year	Industry representative indicated that much of the time the engine is operating, but no water is being pumped (Gantner, 2005).

Information from State OGC and industry contacts enabled us to define the relevant portions of the design of the average coal bed methane well. The most common pipe size reported to be used by a pumping system supplier, 2 and 3/8 inch, coincided with what the Wyoming OGC reported to be a common pipe size on permit applications (Weatherford, 2005; Strong, 2005). A representative of one production company operating in Wyoming reported that the vast majority of the pumps it used (over 90 percent) are electric submersible pumps (ESP) with an approximate efficiency of 60 percent (Olson, 2005). Though producers in other areas, such as the San Juan Basin and the Raton Basin, have reported predominantly using other types of pumps, including plunger lifts, progressing cavity pumps and rod lift systems, the 60 percent efficiency estimate has been used for all areas. Manufacturer information indicates that the ESP is the least efficient type of pump and therefore this results in a conservative estimate (Weatherford, 2005b). A simple diagram of the assumed pumping system that results from this information is provided in Figure 2-6.

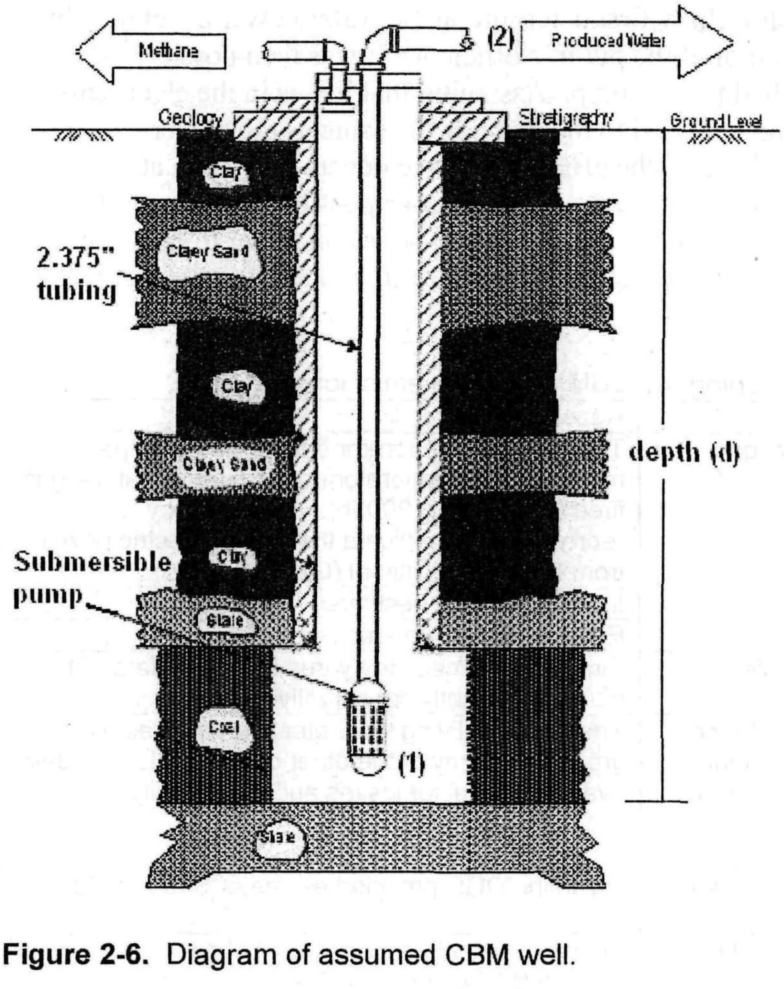


Figure 2-6. Diagram of assumed CBM well.

With the assumption that minor losses from joints in the pipe or other inconsistencies in the system are negligible and that the exit velocity at the top of the pipe is near zero, then the power imparted to the water by the pump is equal to the power required to overcome the elevation difference and the "frictional losses" (the energy lost to heat and turbulence at the pipe-water interface). This system can be described using a form of the Bernoulli equation, where the energy at the exit of the pipe (labeled "2" in Figure 2-6) is equal to the sum of the energy at the inlet to the pump (labeled "1" in Figure 2-6) plus the energy supplied by the pump and the frictional losses as shown in Calculation 4.

Calculation 4. Modified Bernoulli equation

$$z_1 + \frac{P_1}{\gamma} + \frac{v_1^2}{2g} + H_P - H_L = z_2 + \frac{P_2}{\gamma} + \frac{v_2^2}{2g}$$

where:

z = Elevation
P = Pressure
γ = Specific weight of water, 62.4 lb/ft^2
v = Velocity
H_p = The head imparted by the pump (feet)
H_L = The head lost to friction (feet)

If the exit velocity is excluded and the downhole pressure assumed to be negligible, then the above equation reduces to:

$$z_1 + H_P + H_L = z_2$$

rearranging and substituting the depth (d) for $z_2 - z_1$ shows that the energy imparted by the pump, H_p, is given by:

$$H_P = d + H_L$$

H_L is somewhat difficult to calculate due to the dependence of the calculation method on the flowrate. For the same pipe under a certain threshold flowrate, the flow is laminar and it is a simple matter to determine the frictional loss using the Darcy-Weisbach equation. However, above that threshold flowrate for the same pipe, the flow becomes turbulent and there are several possible methods of estimating the frictional loss. In this study, we have used the Hazen-Williams equation to estimate frictional losses for flowrates that imply a Reynolds Number above 3000 (see Calculation 5).

The flowrate itself is not a trivial matter to estimate. The information obtained from the State OCD is total annual water production. One option was to assume that flow is constant for 8760 hours per year. However, based on information generously provided by Bruce Gantner (2005) of the New Mexico Oil and Gas Association, it was clear that pumps are frequently operating without pumping any fluid apart from gases. This would occur when the water level in the well is drawn down low enough that water needs to be pumped only intermittently. Effectively, this signifies that a portion of the time the engines are operating with a very low load when no water is being pumped and the rest of the time are operating at a load sufficient to pump water. At this time, it has not been possible to estimate the fraction of time that the pumps are actually moving water and fifty percent has been assumed. This means that fifty percent of the time engines are assumed to be idling with only ten percent of their loaded horsepower. These idling emissions, discussed below, are added to the emissions resulting from the work performed to lift water from the wells. In terms of the determination of flowrates, this 50 percent operational schedule means that flowrates are determined based on the total annual water production divided by 4,380 hours per year of pumping.

Calculation 5. Method for calculating the frictional losses (H_L)

$$R = \frac{D \times V}{\nu}$$

where:

R = The Reynolds number
D = The diameter of the pipe
V = The velocity of flow (flowrate divided by cross-sectional area of pipe)
v = The kinematic viscosity of water (assumed = 1.0)

If R < 3000 then,

$$H_L = f \times \frac{L}{D}\frac{V^2}{2g} \qquad \text{(the Darcy-Weisbach equation)}$$

where
L = The length of pipe
D = The diameter of pipe
V = The velocity of flow
g = The acceleration of gravity

and with

$$f = \frac{64}{R}$$

Else if R > 3000,

$$H_L = \frac{V^{1.85} L}{(1.318 \times C_H)^{1.85} \times R^{1.17}} \qquad \text{(the Hazen-Williams equation)}$$

where:

V = The velocity of flow
L = The length of pipe
R = The hydraulic radius (cross-sectional area of pipe divided by the wetted perimeter)
C_H = The Hazen-Williams coefficient, 140 for plastics

As shown in calculations 4 and 5, determining the frictional loss and adding that to the depth of the well yields the energy that is imparted by the pump. Then, to determine the power of the pump we apply the equation shown in Calculation 6.

Calculation 6. Determining the pump power

$$P = H_P \times Q \times \gamma / 550$$

where

P = the power supplied by the pump (hp)
H_P = the energy supplied by the pump (ft)
Q = the flowrate (cfs)
γ = specific weight of water (62.4 lb/ft^2)

Once the power delivered by the pump was determined, determining the power developed by the engine was a matter of applying the pump and generator efficiencies as shown in Calculation 7.

Calculation 7. Determining the engine power

$$P_E = P / \varepsilon_P / \varepsilon_G$$

where

P_E = the power developed by the engine (hp)
P = the power delivered by the pump (hp)
ε_P = the efficiency of the pump (0.60)
ε_G = the efficiency of the generator (0.85)

Total annual engine activity due to pumping water at one well was estimated as the product of the power developed by the engine and 4,380 hours per year. To this activity, with units of horsepower-hours, was added the engine activity while not pumping water. Engines that are idling while no water is being pumped are assumed to operate at ten percent of their operational load. Thus, for a single well, the idling engine activity was calculated as ten percent of the pumping horsepower determined in Calculation 7 multiplied by 4,380 hours per year. The total engine activity was thus the sum of 4,380 hours of engine activity while idling plus 4,380 hours of engine activity while pumping. Emissions were then calculated in New Mexico and Colorado as the product of total engine activity and the 12 g/hp-hr emission factor for natural gas fired engines (SCC 2268006005) provided in EPA's NONROAD (2004). For Wyoming, an emission factor was developed that reflected the controls imposed by WYDEQ on natural gas fired engines and the use of some diesel generators to power pumps. That emission factor is 6.1 g/hp-hr.

The total emissions estimated by this method for Colorado, New Mexico and Wyoming are presented in Table 2-15. This method has resulted in per well NOx emissions for these three states of 0.59 tpy/well in Colorado, 0.06 tpy/well in New Mexico and 0.23 tpy/well in Wyoming. This represents a significant increase over the emissions predicted by the previous method, 0.080

tpy/well, 0.010 tpy/well and 0.067 tpy/well respectively. Despite having a large number of wells, New Mexico's emissions from CBM engines are substantially less than in Colorado and Wyoming. This is a result of the relatively low water production in New Mexico. This low water production implies less work is done by engines. Industry representatives indicated that the San Juan Basin, where most coalbed methane production occurs in New Mexico, is a mature field where at this point comparatively little dewatering is necessary (Gantner, 2005).

Table 2-15. State total NOx emissions from coalbed methane engines.

State	CBM Wells	Engine Emissions - Pumping (ton/yr)	Engine Emissions - Idling (ton/yr)	Total Engine Emissions (ton/yr)
Colorado	2,535	1,354	135	1,489
New Mexico	3,516	204	20	225
Wyoming	12,147	1,298	130	1,428

VOC AND MINOR NOx SOURCE INVENTORY

In addition to the area sources identified as potentially major sources of NOx emissions, we have estimated emissions for several other processes occurring at oil and gas wellheads. Emissions were estimated for both NOx and VOC using well-specific production and emission factors provided by the Wyoming Department of Environmental Quality and the Colorado Department of Public Health and Environment. The sources for which emissions were estimated in this portion of the inventory are listed in Table 2-16.

Table 2-16. Emissions sources estimated in the VOC and minor NOx source inventory.

Process	Pollutants	Emission Factors Units
Tanks - Flashing & Standing/Working/Breathing	VOC	lbs per year/barrel per day of condensate production
Glycol Dehydration Units	VOC	lbs per year/million cubic feet per day of gas production
Heaters	NOx, CO	lbs per year/well site
Pneumatic Devices	VOC	tons per year/well
Completion - Flaring and Venting	VOC, NOx, CO	tons/completion

As proposed in the work plan, the default emission factors used for these sources were the emission factors provided by the Wyoming DEQ (2004b). State agencies and industry were given the option of providing their own emission factors. Only the CDPHE (2005) provided alternate emission factors. The emission factors used are presented in Table 2-17.

Table 2-17. Wyoming DEQ emission factors.

Gas Wells	Emission Factor	Oil Wells Source	Emission Factor
Condensate Tanks	3,271 lbs VOC per year/BPD	Heater	0.005 lbs NOx per barrel
Dehydrator	27,485 lbs per year/MMCFD	Pneumatic Devices	0.1 tons VOC / well
Heater	1,752.0 lbs NOx per year/well	Tanks	160.0 lbs VOC per year / BPD
Completion	86.0 tons VOC/well completion		
	1.75 tons NOx/well completion		
Pneumatic Devices	0.2 tons VOC per year/well		
CDPHE Emission Factors			
Completion	16.664 ton VOC/well completion		
	0.85 ton NOx/well completion[1]		

[1]Though the CDPHE only provided an emission factor for VOC, we have used the assumptions used by the CDPHE to prepare that emission factor in order to develop an appropriate NOx emission factor.
[2]For documentation of the Wyoming DEQ emission factors, refer to Appendix A.

To use these emission factors, it was necessary to obtain well-specific production data from the State oil and gas commissions. In most cases, the necessary data was either compiled by the oil and gas commission and submitted to ENVIRON or was downloaded from the oil and gas commission's website. The list of well-specific information obtained from the oil and gas commissions is presented in Table 2-18. The list of sources for this production data is similar to the list of sources of drill permit data, but is included here as Table 2-19 for completeness.

Table 2-18. Well-specific data obtained from the oil and gas commissions.

2002 oil produced
2002 gas produced
2002 water produced
well location (latitude/longitude)
well field
well formation
well depth
well class (oil/gas)
coal bed methane (yes/no)
completion date

Table 2-19. Sources of well-specific production data.

States with Oil/Gas Production in 2002	Source of Production Data
Alaska	Alaska Oil and Gas Conservation Commission (AK OGCC), 2005
Arizona	Arizona Geological Survey (AZ GS), 2005
Colorado	Colorado Oil and Gas Conservation Commission (CO OGCC), 2005
Montana	Montana Board of Oil and Gas Conservation (MT BOGC), 2005
North Dakota	North Dakota Industrial Commission, Oil and Gas Division (ND OGD), 2005
New Mexico	New Mexico Environmental Department (NM ED), 2005 and New Mexico Oil Conservation Division (NM OCD), 2004
Nevada	Nevada Division of Minerals (NV DM), 2005
Oregon	Oregon Department of Geology and Mineral Industries (OR DGMI), 2005
South Dakota	South Dakota Department of Environment & Natural Resources, Minerals and Mining Program (SD MMP), 2005
Utah	Utah Division of Oil, Gas and Mining (UT DOGM), 2005
Wyoming	Wyoming Oil and Gas Conservation Commission (WY OGCC), 2005

The fact that records were obtained for all wells that contained each of the fields in Table 2-18 did not mean that for every well all those fields were populated. The most important fields for the purposes of this inventory were those containing the production figures. These appeared to be well maintained. However, in some cases the completion date and the well class, which are also used in this emission estimate, were blank. It did not appear possible to obtain additional data for completion dates, and the assumption is that a blank completion date implies the well was completed some time in the past, prior to 2002.

The data provided by the State of Colorado Oil and Gas Commission presented the most difficulty due to the absence of data specifying whether a well was considered an oil or gas well. This information was necessary because the emission factors shown in Table 2-17 were determined specifically for oil wells or gas wells (WYDEQ, 2004b). In order to proceed, it was necessary to divide the wells into these two categories. For the State of Colorado this was accomplished by calculating the ratio of gas production (MCF) to oil production (BBL) for all wells and then determining where an appropriate division would be. The distribution of wells according to their gas oil ratios is presented in Figure 2-7.

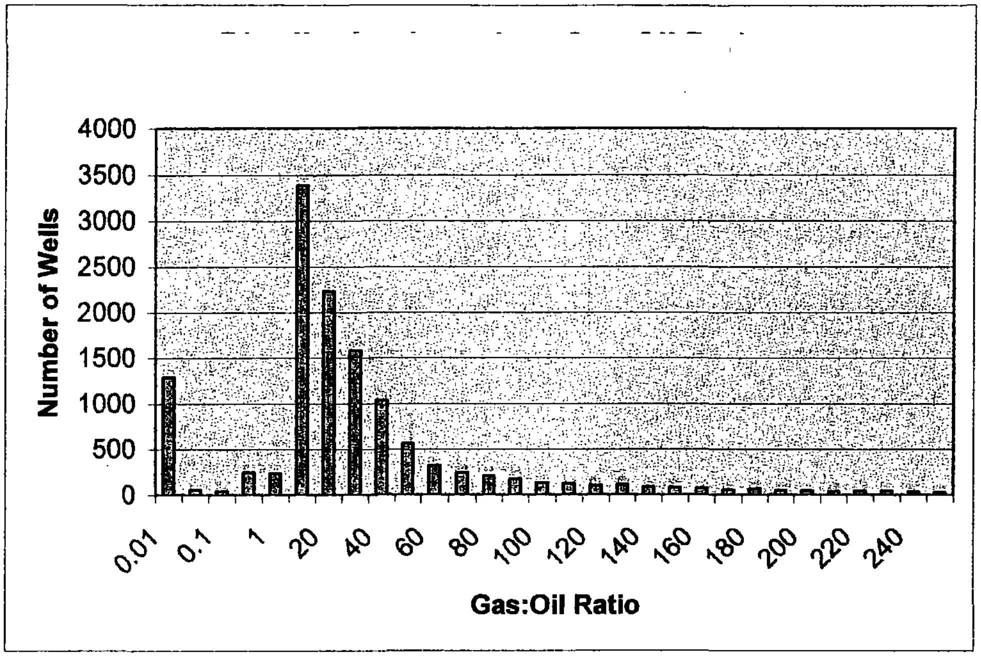


Figure 2-7. Distribution of Colorado wells based on the ratio of gas production to oil production.

There is a clear break in the distribution between wells with a ratio under 0.1 and those with a ratio above 0.1. This break places the great majority of wells into the gas well category. Using a gas:oil ratio of 0.1 to distinguish between oil and gas wells places 1,385 wells in the category of oil wells and 19,847 in the category of gas wells. This may seem an arbitrary division, but it was done based on two considerations. First, this division places the large majority of wells into the category of gas wells. Gas wells have higher emission factors and thus this represents a conservative emissions estimate. Also, the Energy Information Administration estimates over 23 thousand gas wells in the State of Colorado in 2002, which supports this high number of gas wells (EIA, 2005).

The other important division made was between traditional gas wells and coalbed methane gas wells. According to the Wyoming DEQ, the emission factors in Table 2-17 are representative of processes at traditional gas wells, not at coalbed methane wells. The only State for which an identifier was not provided for coalbed methane wells was the State of New Mexico. In the State of New Mexico, coalbed methane wells were identified based on the producing formation reported for the well. The wells producing from one of the formations listed in Table 2-20 were classified as coalbed methane wells. These are the fields indicated for New Mexico in the map of US coalbed methane production produced by the EIA (2004), a section of which is shown in Figure 2-8.

Table 2-20. Coalbed methane producing formations in New Mexico.

Basin Fruitland Coal
Castle Rock Park-Vermejo
Stubblefield Canyon Raton-Vermejo
Van Bremmer Canyon - Vermejo

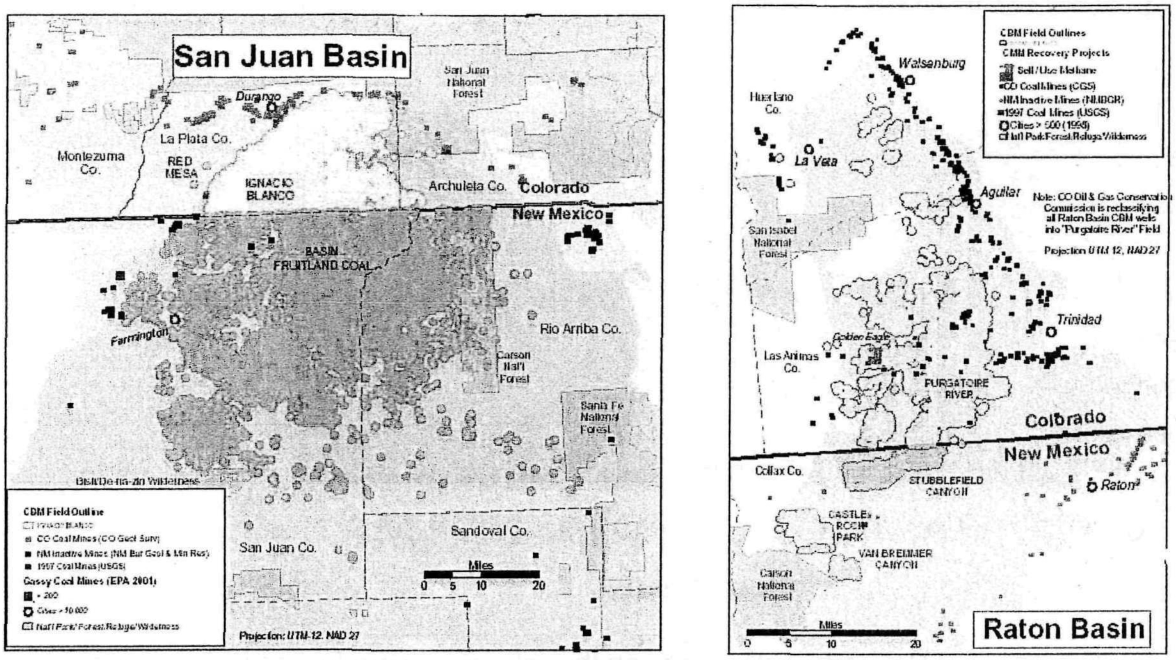


Figure 2-8. Coalbed methane fields in New Mexico.

Having obtained well-specific data from all states, divided those wells into oil and gas wells and then eliminated the coalbed methane wells, there was still one more filtering of the production data required. Because some of the emission factors have units of emissions per well, wells with zero oil and zero gas production and a non-2002 completion date were removed from consideration. This action would prevent emissions from being estimated at wells where no activity actually occurred in 2002.

Several states reported requiring controls on some of the processes considered in this portion of the inventory. The controls reported and the sources of information are presented in Table 2-21. Both the controls reported by the CDPHE and WY DEQ are included in the emission factors provided by those agencies. The inclusion of these controls in the Wyoming emission factors actually presents a small complication, as those emission factors are used to estimate emissions in all other States, including those States that did not report any controls on condensate tanks or completion emissions. Emissions for completion activities are estimated in all States, except North Dakota and Colorado, using the Wyoming emission factors for completions, despite the inclusion of controls in the WY DEQ emission factors. This has been done because the flaring assumed in the emission factor is not very different from the flaring we would assume based only on safety considerations.

Table 2-21. Controls on sources considered in the VOC and minor NOx source inventory.

State	Condensate Tanks	Completion: Flaring & Venting	Source
Colorado		Included in EF provided	CDPHE, 2005; CDPHE, 2005b
Montana	Flare or vapor recovery required	Flare or vapor recovery required	MT DEQ, 2005
North Dakota	Flare or vapor recovery required	Flare or vapor recovery required	ND DH, 2005
Wyoming	Included in EF provided	Included in EF provided	WY DEQ, 2004b

Wyoming DEQ assumed that condensate tanks with greater than 18.3 barrels per day of condensate production would be controlled with an overall efficiency of 98 percent. For wells with condensate production less than 18.3 barrels per day WY DEQ provided an uncontrolled emission factor (see Table 2-17). To account for the absence of controls on condensate tanks in States, emissions were simply estimated for all wells in those States using the uncontrolled emission factor.

In contrast to those States where no controls were reported for condensate tanks, Montana and North Dakota reported that all condensate tanks are required to achieve the same 98 percent control efficiency reported for the larger wells in Wyoming. For these two States, emissions for all condensate tanks were estimated using the controlled emission factors provided by WY DEQ. Montana and North Dakota environmental agencies also reported that completion emissions must be routed to a flare. No modifications were made to account for the completion controls in North Dakota because flaring completion gases whenever possible is already assumed in the Wyoming emission factor. In the State of Montana, however, it was specified that the control efficiency assumed was 98 percent for an elevated flare (MT DEQ, 2005). The control efficiency for a flaring assumed by WY DEQ was only 50 percent based on observations that flares burn with varying opacity, from 0 to 100 percent, indicating that in many cases a significant portion of the fluid is not combusted (WYDEQ, 2004b). To account for the greater control efficiency reported by Montana DEQ, the Wyoming emission factors were adjusted for use in Montana.

Based on a typical well completion log, the Wyoming DEQ assumed that 5.0 MMSCF of gas are flared or vented during 10 days of completion activity. Using the same characteristics of the completion gas as were used by Wyoming DEQ and substituting the Montana DEQ assumption of 98 percent control, it was possible to calculate new emission factors for Montana using AP-42 emission factors for a flare. The details of this calculation, including the assumed gas characteristics are shown in Calculation 8.

Calculation 8. Calculation of completion emission factors for Montana

Assumptions adopted from Wyoming DEQ:

- 5.0 MMCF gas flared or venting daily for 10 days of completion activities
- VOC and HAP weight percent of gas is 9.43
- Gas molecular weight of 18.456 lb/lb-mol
- 1000 Btu/SCF

Information provided by Montana DEQ:

- 100 percent of completion gases must be flared
- flare has a 98 percent destruction efficiency

AP-42 emission factors:

- 0.14 lb NOx/MMBtu
- 0.035 lb CO/MMBtu

<u>VOC Emission Factor</u>

EF = V x (10^6 SCF/MMCF) x F x MW x 1/D x (1 - e) x (ton/2000 lb) x W

with:

EF = VOC emission factor (ton VOC per completion)
V = the volume of gas vented or flared per completion (MMCF per completion)
F = the fraction of gas sent to the flare (1.0 for Montana)
MW = molecular weight of gas (lb/lb-mol)
D = conversion factor, 379 SCF/lb-mol
e = flare destruction efficiency (0.98 for Montana)
W = fraction of gas that is VOC

EF = 50 MMCF x (10^6 SCF/MMCF) x 1 x 18.46 lb/lb-mol x 1/(379 SCF/lb-mol) x (1-0.98) x (ton/2000 lb) x 0.0943
EF = 2.3 tons VOC per completion

<u>NOx Emission Factor</u>

EF = V x (10^6 SCF/MMCF) x F x H x (MMBtu/10^6 Btu) x A x (ton/2000 lb)

with:

EF = NOx emission factor (ton NOx per completion)
V = the volume of gas vented or flared per completion (MMCF per completion)
F = the fraction of gas sent to the flare (1.0 for Montana)
H = the heating value of the gas (1000 Btu/SCF)
A = AP-42 emission factor for a flare (0.14 lb NOx/MMBtu)

EF = 50 MMCF x (10^6 SCF/MMCF) x 1.0 x 1000 Btu/SCF x (MMBtu/10^6 Btu) x 0.14 lb NOx/MMBtu x (ton/2000 lb)
EF = 3.5 ton NOx per completion

A summary of the final gas well emission factors used is presented in Table 2-22. The final oil well emission factors used are those presented in Table 2-17. Having determined the control-adjusted Montana completion emission factors, and the procedure for incorporating condensate controls into emissions calculations, we proceeded to estimate emissions. Emission factors, adjusted as described for controls, were combined with the well data to estimate emissions following the general procedure shown in Calculation 9. For completion emissions in the State of Colorado, the emission factors provided by CDPHE were used. CDPHE personnel indicated that the completion emission factor was based on information for one area of the State and may not be applicable to the entire State (CDPHE, 2005). However, because no additional factor was provided for the rest of the State, this same emission factor has been used for all of Colorado.

Table 2-22. Summary of control-adjusted gas well emission factors for VOC and minor NOx sources.

	Gas Well Process				
State	**Condensate Tanks (lb VOC per year/BPD)**	**Dehydrator (lbs VOC per year/MCFD)**	**Heater (lbs NOx per year/well)**	**Completion (tons per completion)**	**Pneumatic Devices (tons VOC per year/well)**
Alaska	NA	NA		VOC = 86 NOx = 1.75	
Arizona	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Colorado	NA	NA	1,752	VOC = 16.7 NOx = 0.85	0.2
Montana	65	NA	1,752	VOC = 2.3 NOx = 3.5	0.2
Nevada	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
New Mexico	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
North Dakota	65	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Oregon	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
South Dakota	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Utah	3,271	27,485	1,752	VOC = 86 NOx = 1.75	0.2
Wyoming	3,271 (uncontrolled) 65 (controlled)	27,485	1,752	VOC = 86 NOx = 1.75	0.2

Calculation 9 presents a general outline of how emissions were estimated for the VOC and minor NOx processes. For detailed sample calculations for each of these processes, refer to Appendix B. A summary of the emissions estimated for VOC and minor NOx processes is presented in Table 2-23.

Calculation 9. Calculation of wellhead emissions for individual wells

Gas Well

$$E = SUM_i(P_g \times EF_{g,i}) + SUM_j(Pc \times EF_{c,j}) + SUM(EF_w)$$

where:

- E = The 2002 emission
- P_g = 2002 gas production
- $EF_{g,i}$ = Emission factor for gas process i
- P_c = 2002 condensate production
- $EF_{c,j}$ = Emission factor for condensate process j
- EF_w = Per well emission factor

Oil Well

$$E = SUM_i(P_o \times EF_{g,i}) + SUM(EF_w)$$

where:

- E = The 2002 emission
- P_o = 2002 oil production
- $EF_{o,i}$ = Emission factor for oil process i
- EF_w = Per well emission factor

Table 2-23. State total emissions for VOC and minor NOx sources.

State	VOC	NOx
Alaska[1]	430	9
Arizona		
Colorado[2]	25,386	15,924
Idaho		
Montana[3]	5,439	4,721
Nevada	129	5
New Mexico	166,773	13,482
North Dakota	7,740	176
Oregon	34	12
South Dakota	288	47
Utah	34,757	2,143
Washington		
Wyoming	115,027	6,283

[1]Emissions in Alaska estimated only for completion emissions.
[2]Emissions in Colorado not estimated for condensate tanks or glycol dehydrators.
[3]Emissions in Montana not estimated for glycol dehydrators.

Several modifications are represented in this summary table that have not yet been mentioned. Emissions for condensate tanks and glycol dehydrators are not included for the State of

Colorado. In Colorado, those sources are expected to be included in the point source inventory due to the low inventory threshold (CDPHE, 2005b). Nor are emissions included for any process, except completion activities, in the State of Alaska. Again, emissions from the other VOC and minor NOx sources are expected to be included in the State's point source inventory; in this case because wellhead equipment is permitted under the umbrella of larger facilities (AK OGCC, 2005b; AK DEC, 2005b). Emissions have not been estimate for glycol dehydrators in the State of Montana because it was reported that no wellhead dehydrators have been installed in Montana (MT DEQ, 2005).

3. SPATIAL ALLOCATION SURROGATES FOR MODELING

For air quality modeling, the EPA default spatial allocation surrogates were not appropriate for the area source oil and gas production emissions. ENVIRON therefore developed a new set of spatial allocation surrogates to be used in SMOKE to allocate the county-level area source emissions to the appropriate oil and gas fields. This section summarizes the development of these new oil and gas spatial allocation surrogates in the WRAP states.

Spatial allocation surrogates were developed for two modeling domains:

36 km	12 km
Origin (-2736, -2088)	Origin (-2376, -936)
NX = 148, NY = 112	NX = 207, NY = 186

As outlined in Table 3-1, twelve oil and gas emission source categories were assigned to one of four different surrogate categories designed to represent the location of emissions. The oil, gas and water production surrogates were based on production data at known well locations, while the drill rig surrogate was based solely on the number and location of wells drilled.

Table 3-1. Emission sources and surrogate categories.

Source	SCC	Allocation Surrogate	Surrogate Code
Drill rigs	2310000220	Drill Rigs	688
Oil well - heaters	2310010100	Oil Production	686
Oil well - tanks	2310010200	Oil Production	686
Oil well - pneumatic devices	2310010300	Oil Production	686
Compressor engines	2310020600	Gas Production	685
Gas well - heaters	2310021100	Gas Production	685
Gas well - pneumatic devices	2310021300	Gas Production	685
Gas well - dehydration	2310021400	Gas Production	685
Gas well - completion	2310021500	Gas Production	685
CBM pump engines	2310023000	Water production at CBM wells	687
Gas well - tanks, uncontrolled	2310030210	Gas Production	685
Gas well - tanks, controlled	2310030220	Gas Production	685

Methods

Latitude and longitude coordinates for oil and gas wells and drill rigs were obtained for the WRAP states, except California. The locations of all wells and drill rigs are shown in Figure 3-1. Also displayed are the boundaries of the Tribal lands of the Arapahoe and Shoshone of the Wind River Reservation, Assiniboine and Sioux of the Fort Peck Reservation, Jicarilla Apache, Navajo, Southern Ute and Ute Mountain Ute. Note that neither Washington nor Idaho had any wells in the database.

Once the well locations were known, creation of the surrogates took place in several steps, and relied on the use of ArcINFO GIS software.

1. All wells and drill rigs were labeled with the appropriate grid cell IJ values for both the 36 and 12 km domains.
2. For each individual well, the oil, gas and water production values were divided by the total oil, gas and water production values corresponding to the county in which the well was located. This division resulted in determination of the fraction of a county's total production taking place at each well. In the case of drill rigs, the number of drills, rather than the production values, were used.
3. For each unique grid cell / county combination with wells, each well's production fractions were summed to create the surrogate value. This step was repeated for both domains separately.

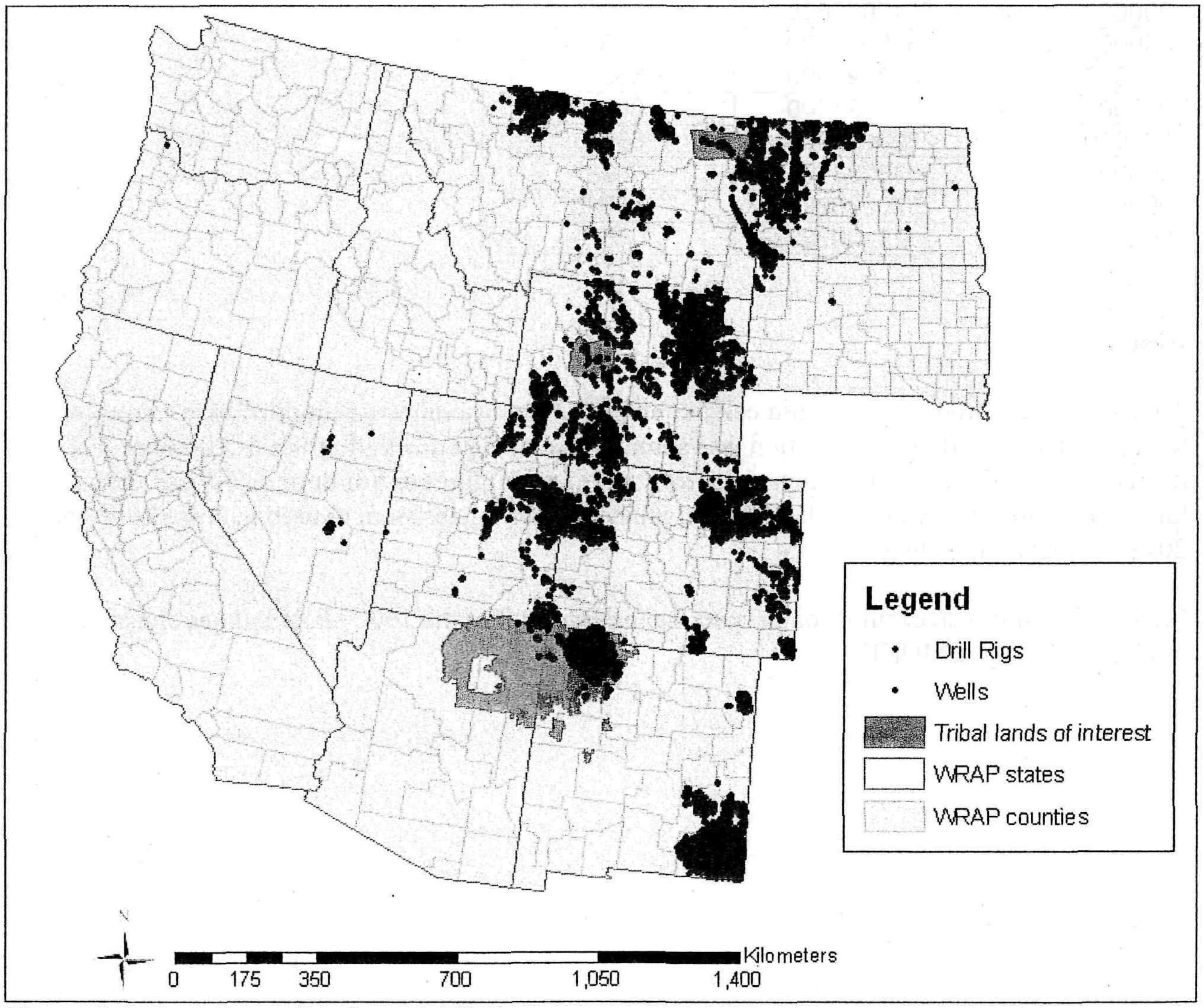


Figure 3-1. Locations of wells and drill rigs.

The surrogate values for each grid cell / county combination were reformatted to comply with the SMOKE emissions processor AGPRO file format. A separate file for each modeling domain was created, and a single accompanying SMOKE AGREF file was created for use with either domain. The purpose of the AGREF file, which is shown in Table 3-2, is to define the relationship between the 3-digit codes chosen to represent each of the four surrogate categories in the AGPRO file and the SCC codes for the twelve oil and gas emission categories to be allocated with these surrogates. This file also specifies which county/state/county (COSTCY) should use the given cross-reference. In this case, COSTCY is set to 000000 to indicate that all states and counties can use these cross-references.

Table 3-2. SMOKE gridding surrogate cross-reference (AGREF) file.

COSTCY	SCC	CODE
000000	2310000220	686
000000	2310010100	688
000000	2310010200	686
000000	2310010300	686
000000	2310020600	686
000000	2310021100	685
000000	2310021300	685
000000	2310021400	685
000000	2310021500	685
000000	2310023000	687
000000	2310030210	685
000000	2310030220	685

Results

To display the surrogates, each grid cell / county surrogate value was multiplied by the county's total production, and then production was summed for each grid cell. Figures 3-2 through 3-5 depict the four different 36 km domain surrogate values; Figures 3-6 through 3-9 depict the 12 km domain surrogate values. These spatial allocation surrogates were used in both the 2002 and 2018 air quality modeling.

Figure 3-10 shows an example daily spatial emissions plot of the 2002 oil and gas emissions as processed through SMOKE.

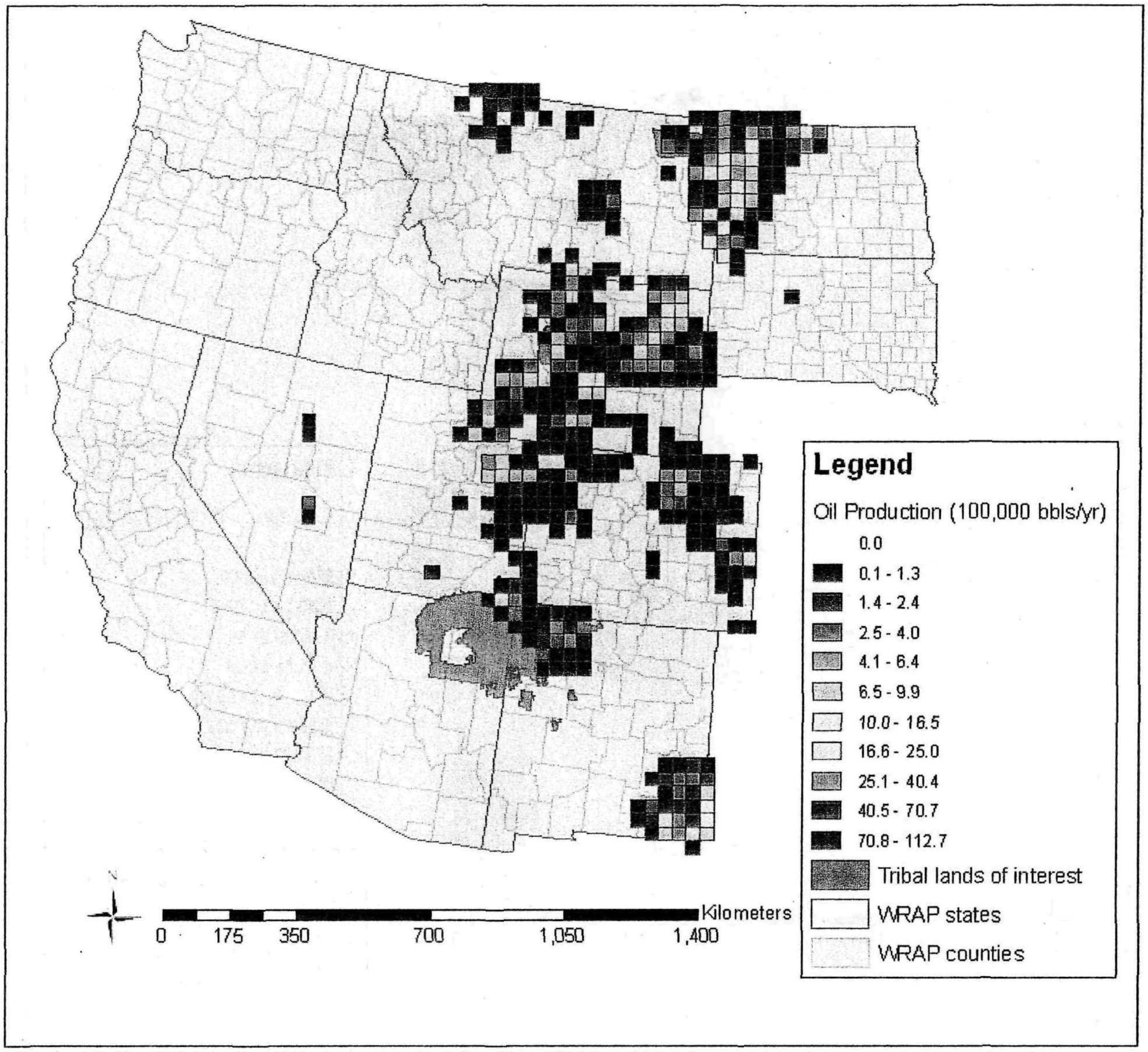


Figure 3-2. Oil production surrogates for the 36 km domain.

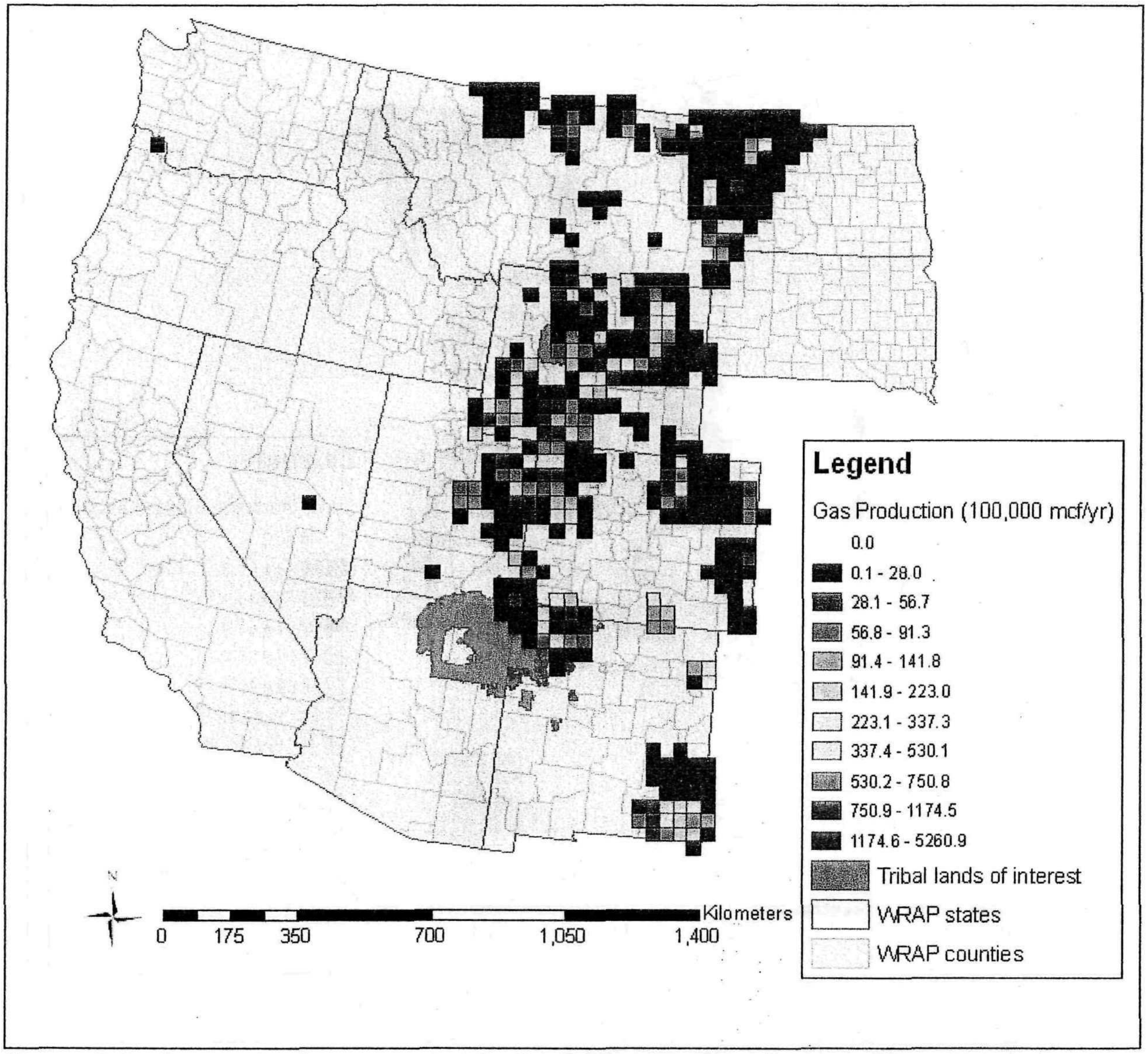


Figure 3-3. Gas production surrogates for the 36 km domain.

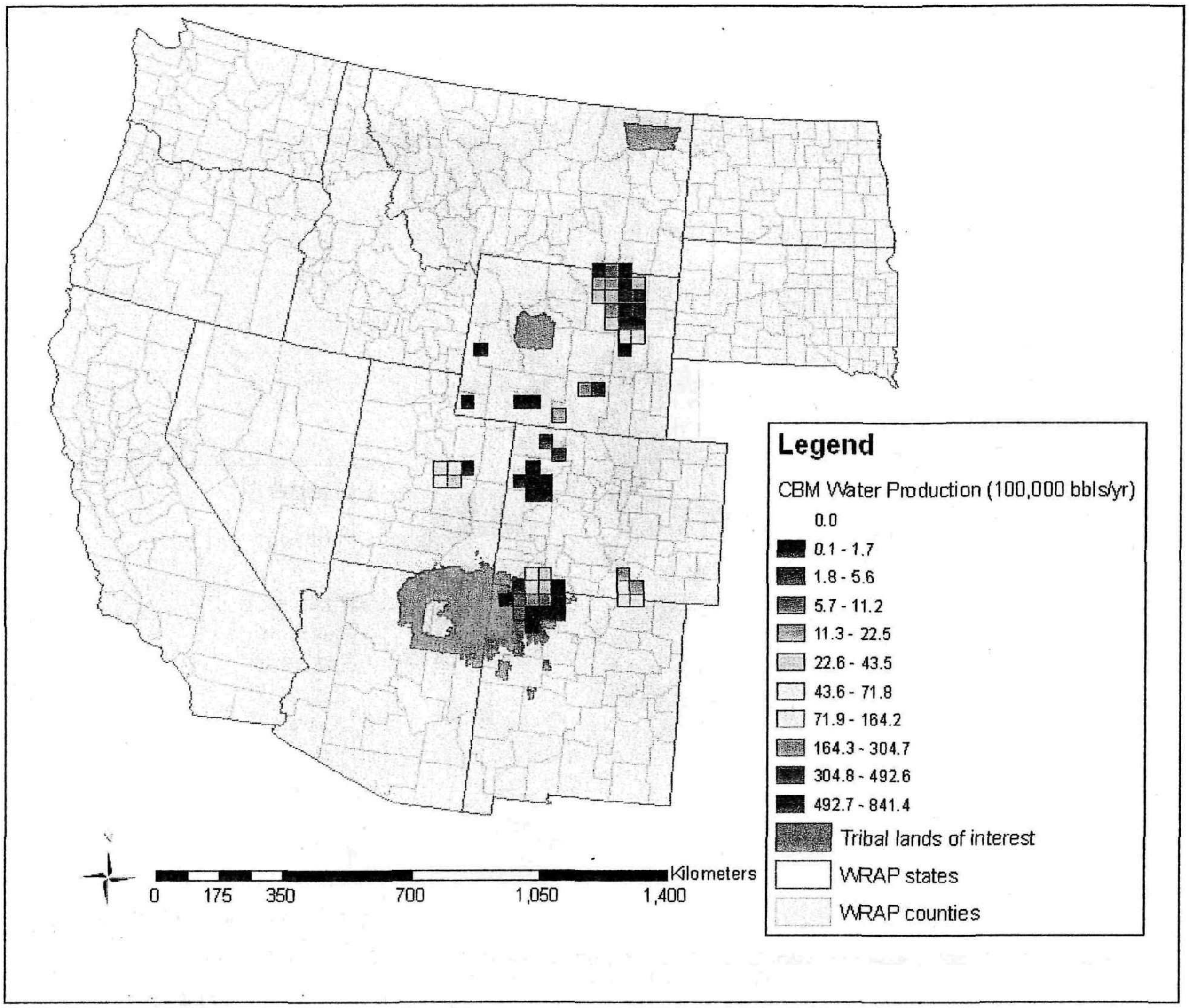


Figure 3-4. CBM well water production surrogates for the 36 km domain.

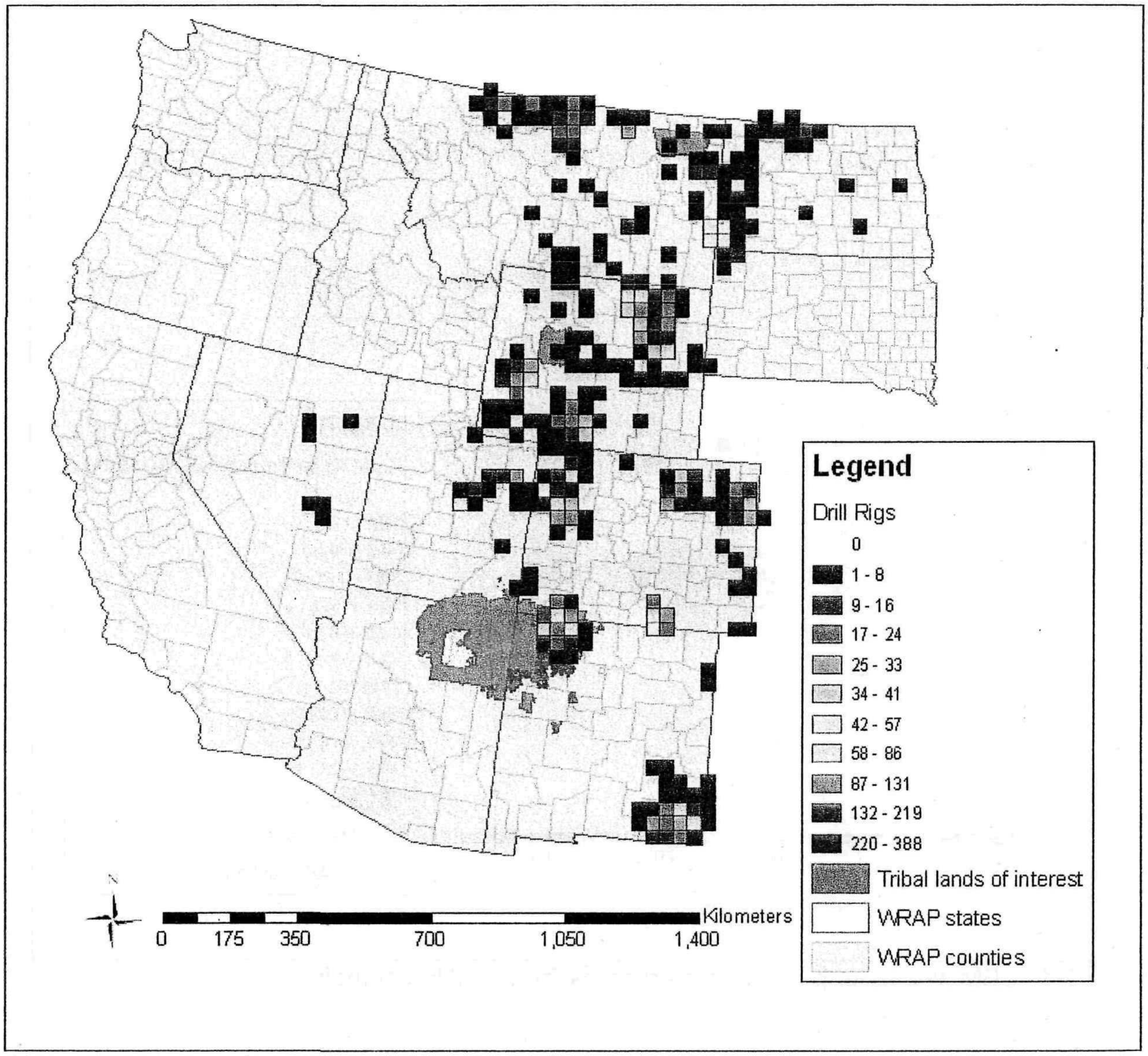


Figure 3-5. Drill rig surrogates for the 36 km domain.

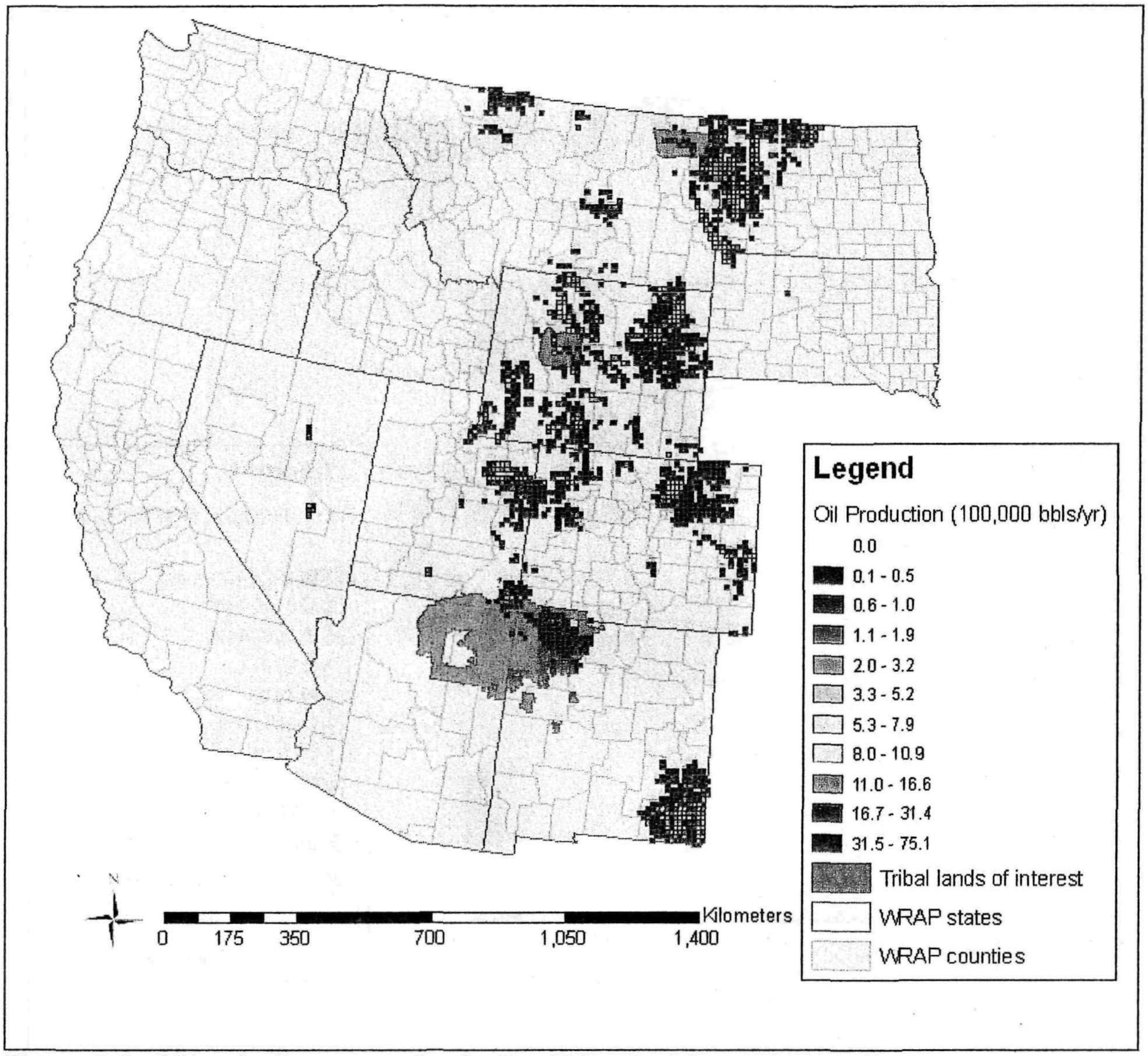


Figure 3-6. Oil production surrogates for the 12 km domain.

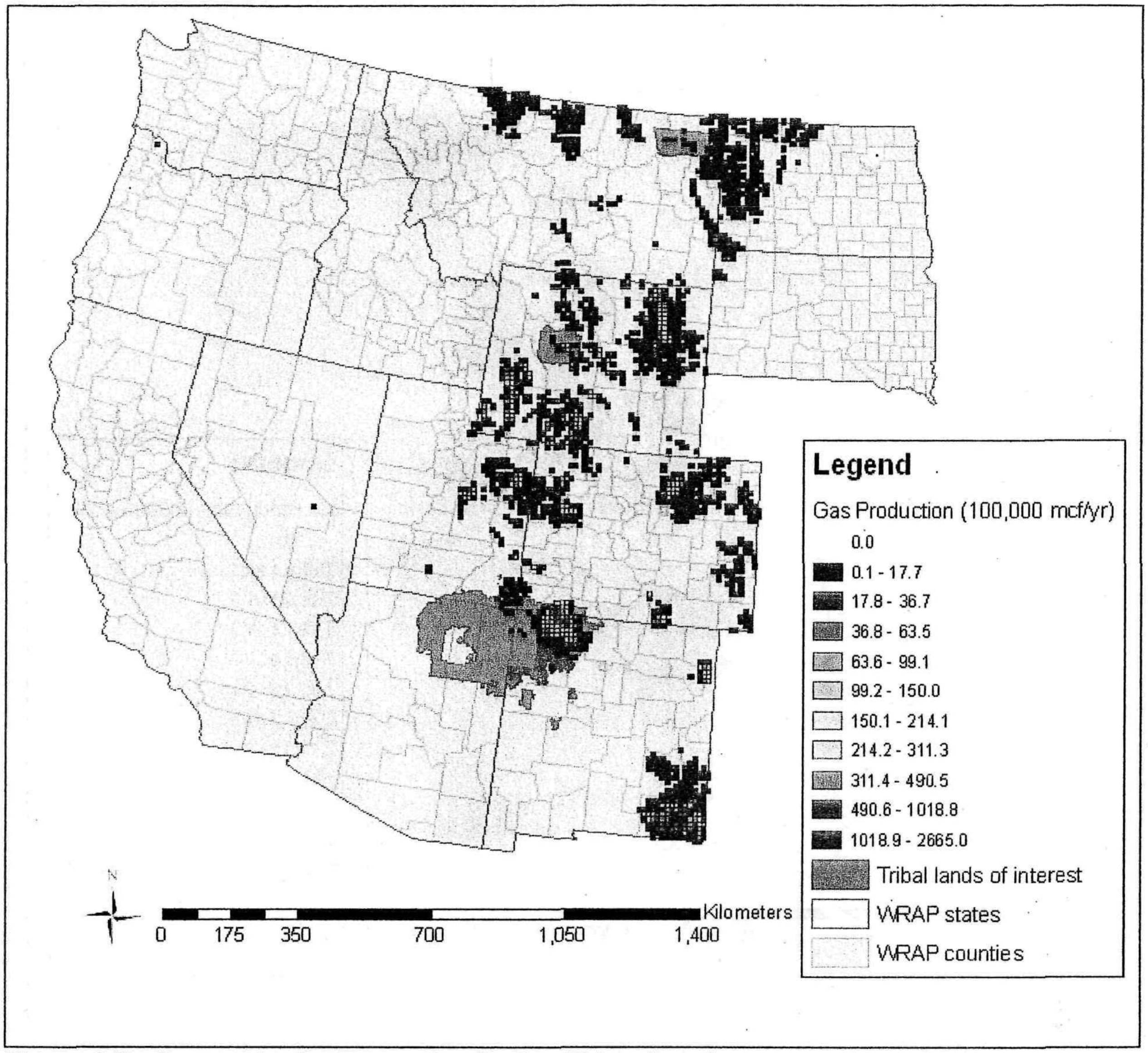


Figure 3-7. Gas production surrogates for the 12 km domain.

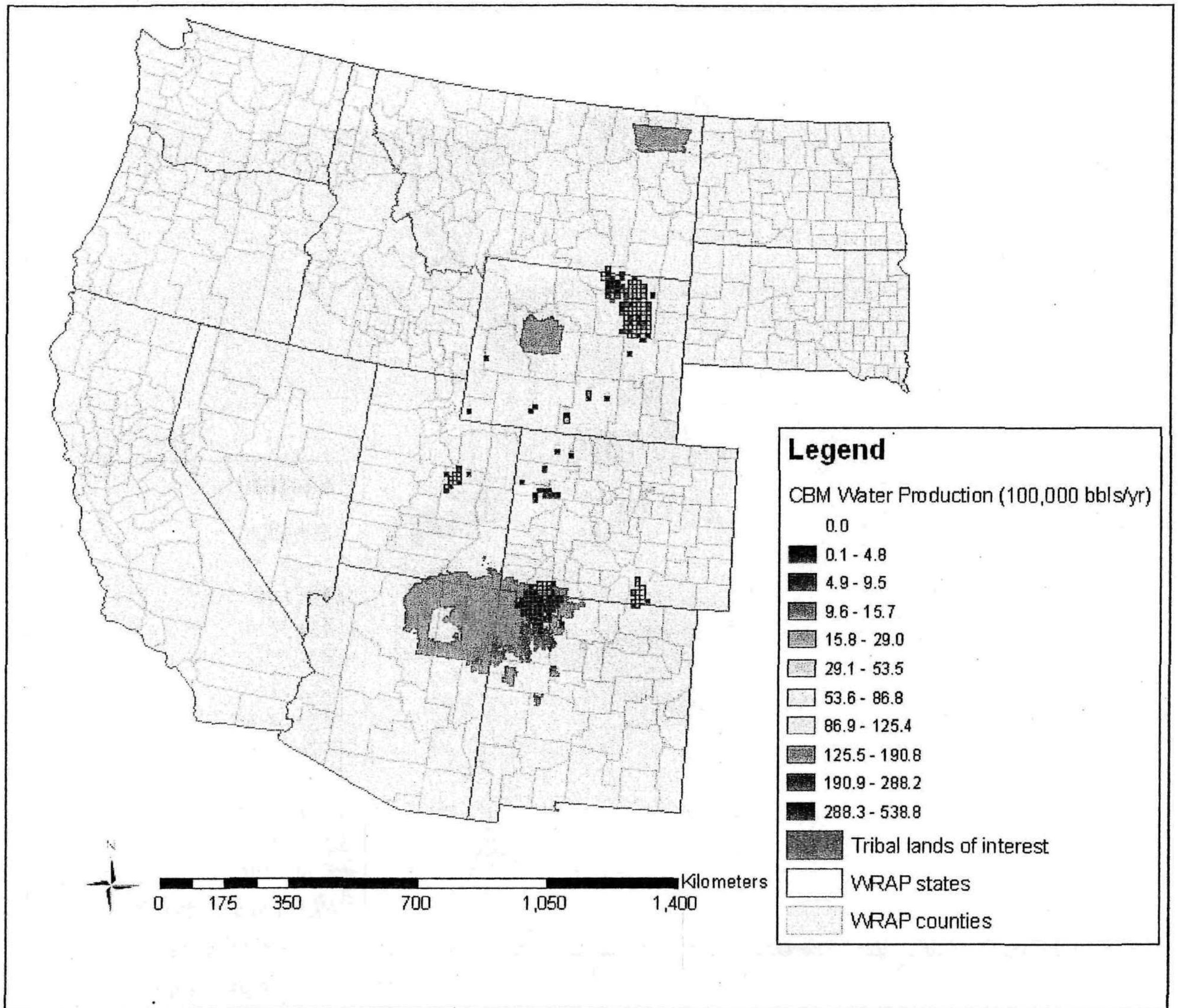


Figure 3-8. CBM well water production surrogates for the 12 km domain.

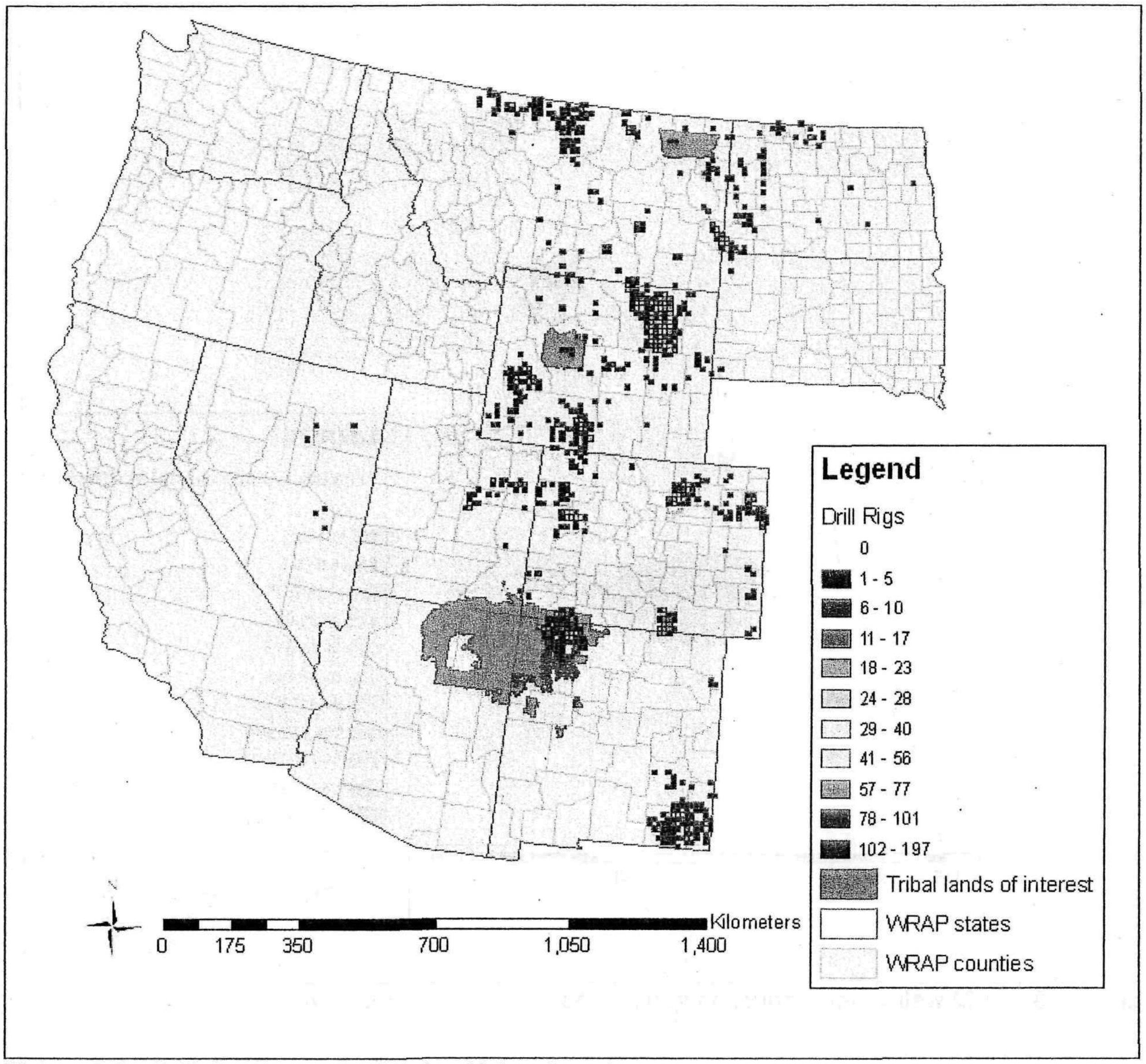


Figure 3-9. Drill rig surrogates for the 12 km domain.

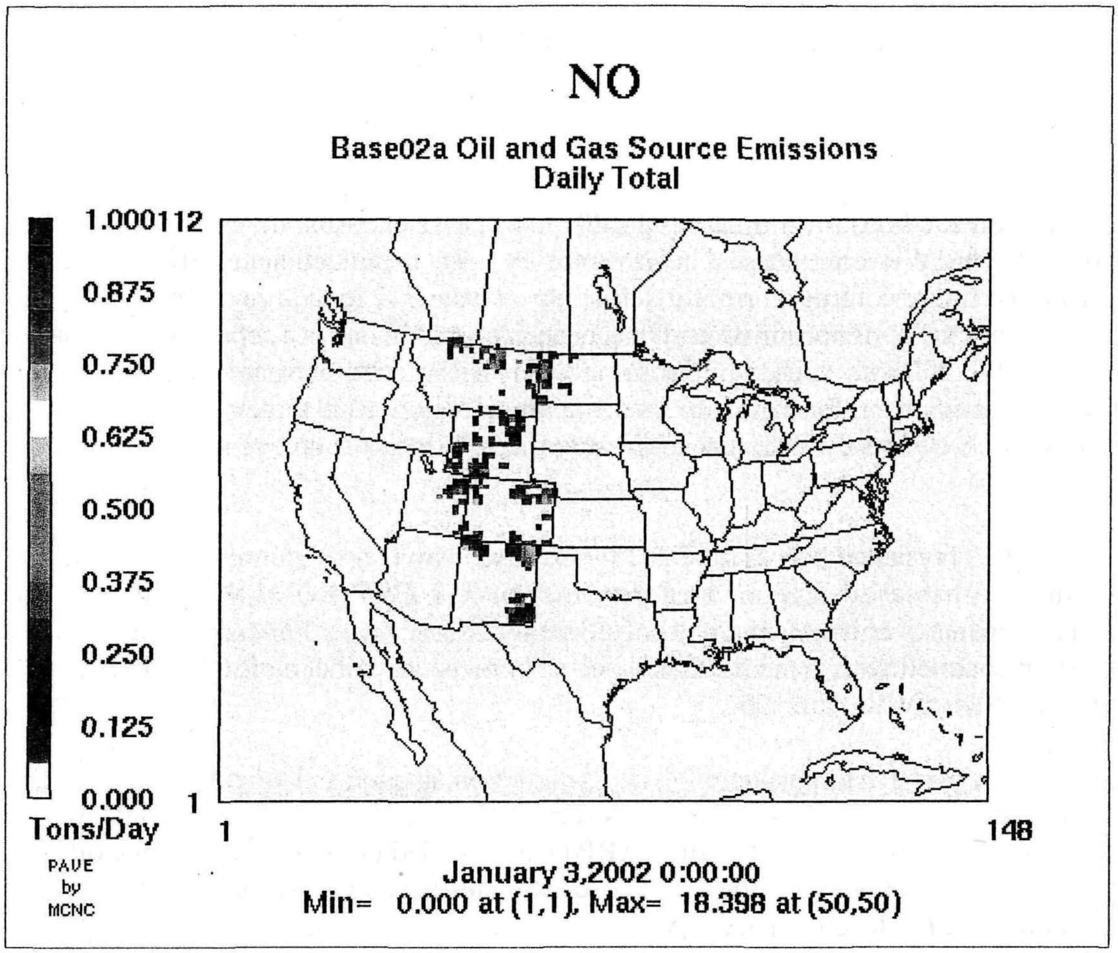


Figure 3-10. Example daily spatial emissions plot of the 2002 oil and gas emissions as processed through SMOKE.

4. 2018 BASE CASE PROJECTIONS

INTRODUCTION

This section describes the methods for estimating the 2018 base case emission inventory of oil and gas area sources for the Western States. This inventory reflects the anticipated 2018 emission levels with the future controls currently defined by state and federal regulation. The 2018 oil and gas point source emissions inventory has been prepared under a separate task, and is reported separately (ERG, 2005b). Thus, while some tables in this section present summaries of the 2018 point source emissions, information about the methodology used to develop those emissions estimates will be found in the report addressing the 2018 point source emissions inventory.

The emissions summaries presented here for the 2018 base case inventory do not include emissions falling under tribal jurisdiction. Under another project, ENVIRON has prepared separate emissions estimates of tribal oil and gas emissions for four tribes. Those emissions estimates have been reconciled with the emissions reported here, and tribal emissions are being reported separately (ERG/ENVIRON, 2005).

Apart from those western states that have no oil or gas production, such as Idaho and Washington, the only state for which area source emissions are not estimated here is the State of California. The California Air Resources Board (CARB) has provided point and area source oil and gas emissions projections directly to WRAP. Those estimates have been adopted by this inventory and are considered to be complete.

Table 4-1a presents a summary of the estimated 2018 NOx emissions from oil and gas area point and area sources in the WRAP States. Table 4-1b presents a similar summary of VOC emissions. The area source emissions are distinguished by source category, except in California where only the total NOx emission from the ARB inventory is given. The point source emissions included in Tables 4-1a and 4-1b include several types of oil and gas facilities that are listed under SIC codes 13**, 492* or 4612. In most states, the major contributors of point source oil and gas emissions are natural gas transmission stations and natural gas processing plants. Crude oil pump stations and large storage sites also make a significant contribution in some states. Notably, the point source inventory methods in the State of Colorado and the State of Alaska are such that the majority of oil and gas emissions sources are included in the point source inventory.

Table 4-1a. 2018 State total NOx emissions (tons) from oil and gas sources.

State	Compressor Engines	Drill Rigs	Wellhead	CBM Pump Engines	Area Source Total	Point Source Total	TOTAL
Alaska		566	2		568	36,501	37,069
Arizona						3,468	3,468
California						13,390	13,390
Colorado		4,051	23,474	184	27,709	15,832	43,541
Idaho						1,734	1,734
Montana	19,029	3,630	7,631	240	30,529	2,554	33,084
Nevada	48	17	7		72	139	212
New Mexico	102,260	7,850	28,420	21	138,551	36,323	174,874
North Dakota	6,751	1,293	633	1	8,678	2,946	11,624
Oregon	42	-	7		48	608	656
South Dakota	414	25	68		507	311	818
Utah	4,736	2,212	6,225	1	13,174	2,314	15,488
Washington						703	703
Wyoming	32,729	7,437	18,466	901	59,533	9,713	69,246
Total	**166,009**	**27,082**	**84,932**	**1,348**	**279,370**	**126,536**	**405,907**

Table 4-1b. 2018 State total VOC emissions (tons) from oil and gas sources.

State	Oil Well, Tanks - Flashing & Standing/Working/Breathing	Oil Well, Pneumatic Devices	Gas Well, Pneumatic Devices	Gas Well, Dehydrators	Gas Well, Completion - Flaring and Venting	Condensate Tanks, Uncontrolled	Condensate Tanks, Controlled	Area Source Total	Point Source Total	TOTAL
Alaska					92			92	2,112	2,204
Arizona									345	345
California									4,962	4,962
Colorado	973	176	4,997		30,912			37,058	59,436	96,494
Idaho									114	114
Montana	4,938	471	1,507	-	637	-	2	7,556	1,024	8,580
Nevada	162	9	1	0	-	-	-	173	32	205
New Mexico	9,357	1,345	5,981	97,981	103,954	110,028	-	328,647	18,339	346,986
North Dakota	8,227	415	120	3,370	659	-	261	13,052	262	13,315
Oregon	-	-	2	18	-	-	-	19	23	42
South Dakota	329	16	15	28	-	-	-	387	38	426
Utah	3,960	304	1,153	13,666	55,569	20,634	-	95,286	3,028	98,314
Washington									36	36
Wyoming	11,369	1,196	3,586	195,221	129,292	62,501	1,469	404,633	10,155	414,788
Total	39,315	3,932	17,361	310,285	321,116	193,163	1,732	886,904	99,907	986,811

Note: Entries with a "-" indicate emissions were estimated to be zero. Entries that are blank indicate that emissions for the state/source combination are not estimated in this area source portion of the inventory.

Table 4-2 compares the results of the 2018 oil and gas inventory with the 2002 oil and gas emissions inventories for NOx. Area source NOx emissions estimated for 2018 show a 114 percent increase over 2002 levels. In the total oil and gas emissions, this large increase in area source emissions is partially offset by a greater than 50 thousand ton decrease in NOx emissions predicted for point sources. The area source and overall increases are most substantial in places where recent development plans predict large-scale oil and gas projects in future years. Such is the case in Montana and Wyoming where major development is anticipated for the Powder River Basin and the Jonah-Pinedale area.

Table 4-2. Change in oil and gas NOx emissions from 2002 to 2018.

State	Compressor Engines	Drill Rigs	Wellhead	CBM Pump Engines	Area Source Total	Point Source Total	TOTAL
Alaska		-35%	-79%		-36%	-20%	-21%
Arizona						27%	27%
California						-20%	-46%
Colorado		-29%	47%	-88%	20%	-39%	-11%
Idaho						-33%	-33%
Montana	839%	248%	62%		292%	-40%	174%
Nevada	46%	-31%	42%		16%	68%	46%
New Mexico	155%	18%	111%	-91%	129%	-36%	49%
North Dakota	131%	-16%	261%		87%	-38%	24%
Oregon	-43%	0%	-43%		-43%	-49%	-48%
South Dakota	46%	-31%	45%		38%	-4%	19%
Utah	100%	227%	191%		154%	-30%	82%
Washington						-45%	-45%
Wyoming	366%	50%	194%	-37%	202%	-35%	99%
Total	**203%**	**26%**	**98%**	**-57%**	**114%**	**-30%**	**30%**

AREA SOURCE OIL AND GAS GROWTH FACTORS

At the most basic level there were two methods used to estimate 2018 county-level oil and gas emissions. The first and by far the dominant method was to develop growth factors that were then used to project from the 2002 oil and gas emissions. A second method was necessary to estimate emissions in the handful of counties that had no 2002 oil and gas emissions but are anticipated to see oil and gas development by 2018. The decision of which method was used to estimate 2018 emissions was based on the existence of oil and gas emissions in 2002. Discussion of the method used for the group of counties with no emissions in 2002 is reserved for later in this section. Here, the data sources and methodologies are presented that were used to project 2002 emissions to 2018 for the three conditions where oil and gas emissions were present in 2002.

Production Growth Factors

The projection of emissions from 2002 to 2018 required the development of county-level growth factors. These growth factors were derived from projections of future oil and gas production reported by several sources. The preferred source of production projections was the Bureau of Land Management (BLM). The BLM periodically prepares Resource Management Plans (RMP) for the lands and mineral resources under its stewardship. RMP for oil and gas production areas typically include an estimate of reasonable foreseeable oil and gas development. The future development is usually estimated as a number of new oil, gas and possibly CBM wells anticipated over the next 10 or 20 years. Table 4-3 provides a brief summary of the reasonable foreseeable development (RFD) scenarios that were ultimately used to obtain the necessary information for creating the 2002 to 2018 growth factors.

Table 4-3. BLM Resource Management Plans considered for use in projections.

RMP ID	RMP_NAME	Source	Start Date	End Date	Gas Wells	Oil Wells	CBM Wells	Wells Drilled
1	Northern San Juan Basin Coal Bed Methane Project	USDA FS, 2004	1/1/2004	1/1/2018			296	296
2	Pinedale RMP	WY BLM, 2005	1/1/2006	1/1/2025	9800			9800
3	Wyoming Powder River Basin Final EIS	WY BLM, 2001	1/1/2002	1/1/2022			81000	81000
4	White River Resource Area RMP EIS	CO BLM, 1996	1/1/1996	1/1/2016	919			1100
5	RMP EIS for Mineral Leasing and Development in Sierra and Otero Counties	NM BLM, 2003	1/1/2003	1/1/2023	36	48		105
6	Dakota Prairie Grasslands Oil and Gas Leasing	USDA FS, 2003	1/1/2003	1/1/2013	450		60	660
7	Farmington Proposed Resource Management Plan	NM BLM, 2003	1/1/2002	1/1/2022	13271	380	2964	16615
8	Desolation Flats Natural Gas Field Development Project	WY BLM, 2004	1/1/2004	1/1/2024	308			474
9	Draft Vernal Resource Management Plan	UT BLM, 2005	1/1/2006	1/1/2021	4345	2055	130	6530
10	Jack Morrow Hills Coordinated Activity	WY BLM, 2004b	7/1/2004	1/1/2021	107		50	255
12	Wind River Natural Gas Project	BIA, 2004	1/1/2005	1/1/2018	325			325
13	Powder River and Billings Resource Management Plan	MT DEQ, 2003	1/1/2003	1/1/2023	800		18200	19000
14	Powder River and Billings Resource Management Plan	MT DEQ, 2003	1/1/2003	1/1/2023	250		6400	6650
15	Powder River and Billings Resource Management Plan	MT DEQ, 2003	1/1/2003	1/1/2023	150			150

As shown in Table 4-3, we obtained a number of RMPs covering a large portion of the WRAP production areas. Figure 4-1 shows the approximate area covered by these resource management plans. Despite the broad combined coverage of these plans, there are some significant production areas for which management plans could not be located.

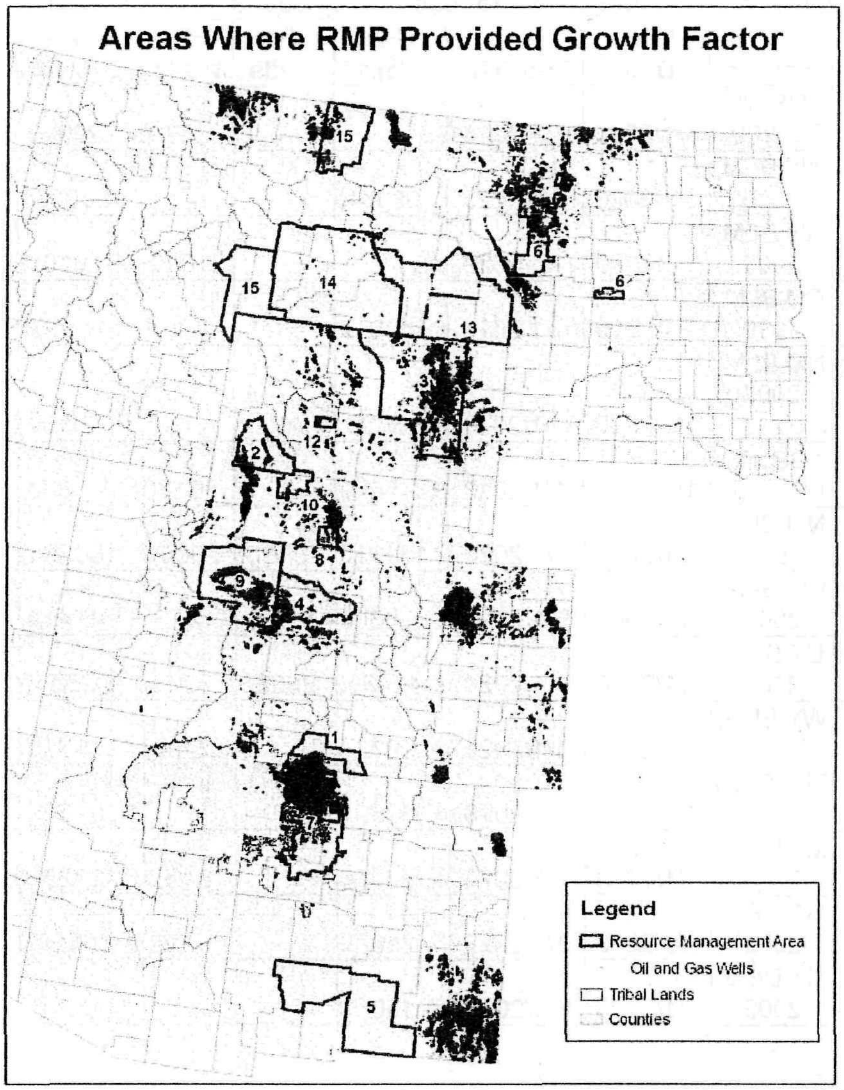


Figure 4-1. Coverage of resource management plans ultimately used to create growth factors.

For some of the areas where it was not possible to obtain recent local development forecasts from the BLM, other sources of local data were identified. For example, the Alaska Department of Natural Resources (AK DNR, 2004) prepares 20-year production forecasts that were used in this effort. Other local sources of data were considered, but were ultimately discarded due either to a lack of detail, the reporting of only the next two or three years, or for a combination of inadequate detail and time-span. Thus, for the areas not covered by the RMP listed in Table 4-3 and not in the State of Alaska, regional production forecasts published by the Energy Information Administration (EIA, 2005b) were used.

The EIA has published projection forecasts out to 2025. For production areas where EIA forecasts were the only source of data identified, separate oil and gas growth factors have been calculated as the 2018 regional production forecast by the EIA divided by 2002 regional production reported by the EIA. There are three EIA growth regions in which some portion of emissions in that region were projected using EIA data. Those regions are the Rocky Mountain Region, the Southwest Region and the West Coast Region. Growth factors developed for those regions based on the EIA's production forecasts are shown in Table 4-4. The delineation of those regions is shown in Figure 4-2.

Table 4-4. 2002 to 2018 oil and gas growth factors based on EIA forecasts.

Region	Oil Production	Gas Production
Rocky Mountain	1.334	1.458
Southwest	0.866	1.354
West Coast	0.601	0.568

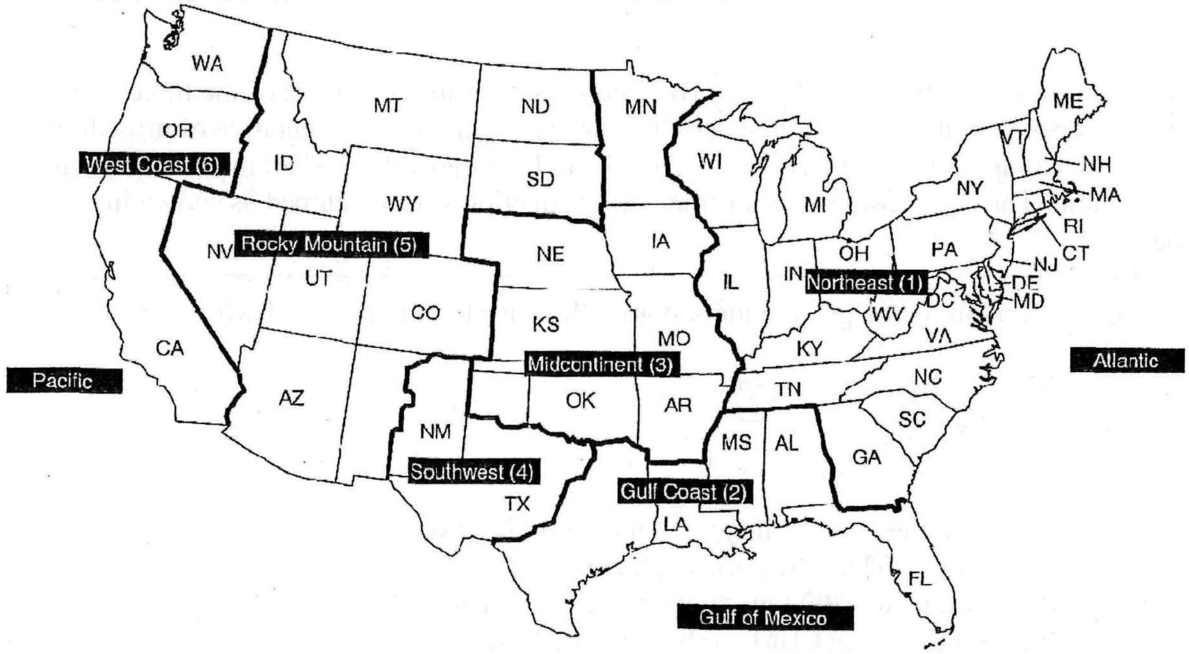


Figure 4-2. EIA production forecasting regions.

Projections to 2018 based on the BLM resource management plans or Alaska DNR data were made using growth factors derived from the proposed future development and the actual 2002 activity. In order to estimate the future number of wells, both the number of wells installed and the number of wells plugged and abandoned had to be estimated. The RMPs do not include estimates of the number of wells that will be plugged and abandoned in future years. The historical plugging and abandoning of wells was, however, available from the OGCs. Thus, lacking other projections of future well abandonment, we used OGC data to estimate the number of wells plugged and abandoned annually at the county level. We then developed an estimate of the future number of wells in a production area based on the number of existing wells in 2002, the number of new wells anticipated by the RMP and the estimated number of wells that would be abandoned based on the assumed persistence of historical abandonment rates. The calculation of a growth factor was thus accomplished as shown in Calculation 1.

Calculation 1: Determination of CBM, oil and gas well growth factor based on BLM RMP

$$G = \frac{(W_{02} + W_f - W_P)}{W_{02}}$$

where:

G = the 2002 to 2018 growth factor
W_{02} = the wells (oil/gas/CBM) active in 2002
W_f = the wells (oil/gas/CBM) forecast to be added by 2018
W_P = the wells (oil/gas/CBM) estimated to be plugged and abandoned by 2018

Because gas production at all well types drives compressor emissions, none of the three growth factors developed for oil wells, gas wells or CBM wells was alone representative of growth in compression. Compressor engine emissions needed to be projected based on the total growth in gas production. Thus a growth factor for total gas production was developed as shown in Calculation 2.

Calculation 2: Derivation of a gas production growth factor based on BLM RMP

$$G_{gas} = \frac{\sum_i (W_{02,i} + W_{f,i} - W_{P,i}) * P_i}{\sum_i P_i * W_{02,i}}$$

where:

i refers to the three well types: oil, gas and CBM
G_{gas} = the 2002 to 2018 growth factor
P_i = the average 2002 production of an oil/gas/CBM well
$W_{02,i}$ = the oil/gas/CBM wells active in 2002
$W_{f,i}$ = the oil/gas/CBM wells forecast to be added by 2018
$W_{P,i}$ = the oil/gas/CBM wells estimated to be plugged and abandoned by 2018

In areas with coverage by a RMP, a separate growth factor was estimated for drill rig activity as the number of wells drilled per year suggested by the development scenario divided by the number of wells drilled in the same area in 2002. A growth factor for drilling in areas where EIA forecasts were used was determined based on the total predicted growth in well drilling in the lower 48 states as reported the EIA forecast, as regional drilling growth was not available. 27.25 thousand wells are anticipated to be drilled in the lower 48 states in 2018, versus 25.45 thousand wells drilled in 2002. From this information a drill rig activity growth factor of 1.071 was calculated.

A total of eight types of growth factors were used to project 2018 oil and gas emissions; three types were developed from EIA forecasts, and five types were based on local production projections. A summary of these eight types of growth factors is presented in Table 4-5. The estimation of emissions in the year 2018 using these growth factors is discussed below.

Table 4-5. Projection growth factors.

ID	Data Source	Growth Factor	Derivation
G1	EIA	Gas production	2018 estimated gas production for the region divided by 2002 gas production for the region
G2	EIA	Oil production	2018 estimated oil production for the region divided by 2002 gas production for the region
G3	EIA	Well drilling	2018 estimated wells drilled in the lower 48 divided by 2002 wells drilled in the lower 48
G4	Local	Gas wells	2018 estimated gas wells in the planning area divided by 2002 gas wells in the planning area (Calculation 1)
G5	Local	Oil wells	2018 estimated oil wells in the planning area divided by 2002 oil wells in the planning area (Calculation 1)
G6	Local	CBM wells	2018 estimated CBM wells in the planning area divided by 2002 CBM wells in the planning area (Calculation 1)
G7	Local	Gas production	2018 estimated total gas production in the planning area divided by total 2002 gas production in the planning area (Calculation 2).
G8	Local	Well drilling	Number of wells drilled per year suggested by the development forecast divided by the number of wells drilled in 2002

2018 Emissions Projections

In all counties having 2002 emissions for a given oil and gas area source process, the 2018 emissions estimate for that process was made by applying a growth factor to the 2002 emissions and then adjusting the estimate to incorporate future year controls. As growth factors were developed for production areas rather than counties, it was necessary to intersect the production areas with the WRAP counties to determine which growth factor to apply in each county. This intersection yielded three distinct conditions: Counties entirely within a RMP area, counties partially within an RMP area and counties not in a RMP area. In the counties only partially intersected by a RMP area, it was necessary to apply BLM-based growth factors to the fraction of the wells in the RMP area and EIA-based growth factors to the remaining wells. The general formula used to estimate 2018 emissions for the process-specific emissions estimates is presented in Calculation 3. Which of the eight growth factors were applied to each of the emissions sources is stipulated in Tables 4-6 and 4-7.

Calculation 3. General formula for projecting process-specific emissions estimates

$$E_{18} = G * E_{02}$$

where:

E_{18} = the emissions from a process in 2018

G = the growth factor for the process, as indicated in Tables 4-6 and 4-7

E_{02} = the emissions from a process in 2002

Table 4-6. Growth factor used for each source in areas where local plans were used.

Source	Growth Factor*
Compressor Engines	Local Gas Production (ID = G7)
CBM Pump Engines	Emissions grown based on CBM well growth factor (ID = G6)
Oil Well - Minor NOx & VOC sources	Emissions grown based on oil well growth factor (ID = G5)
Gas Well - Minor NOx & VOC sources	Emissions grown based on gas well growth factor (ID = G4)
Drill Rigs	Emissions grown based on growth in number of wells drilled annually (ID = G8)

* IDs correspond to those assigned in Table 4-5

Table 4-7. Growth factor used for each source in areas where EIA data were used.

Source	Growth Factor*
Compressor Engines	Emissions grown based on gas production growth factor (ID = G1)
CBM Pump Engines	Emissions grown based on gas production growth factor (ID = G1)
Oil Well - Minor NOx & VOC sources	Emissions grown based on oil production growth factor (ID = G2)
Gas Well - Minor NOx & VOC sources	Emissions grown based on gas production growth factor (ID = G1)
Drill Rigs	Emissions grown based on growth in wells drilled (ID = G3)

* IDs correspond to those assigned in Table 4-5

Figure 4-3 shows a sample of how different growth rates would be applied to areas that, while physically near each other, fell in distinct EIA forecast regions or one inside and the other outside of a RMP area. Figure 4-4 then displays the growth factors developed for gas production in the WRAP states. A complete list of the growth factors developed to project 2002 area source oil and gas emissions to 2018 is provided as Appendix D.

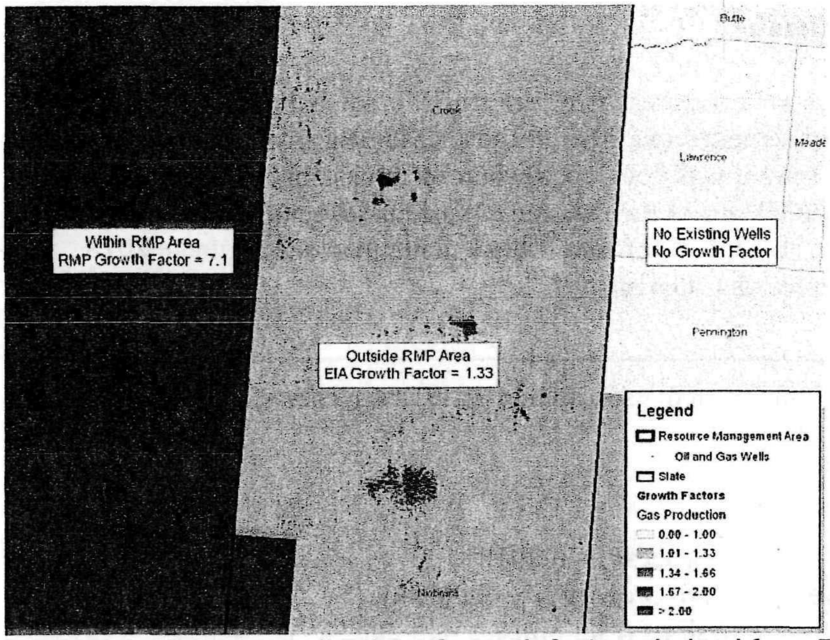


Figure 4-3. Sample application of growth factors derived from RMP and from EIA sources.

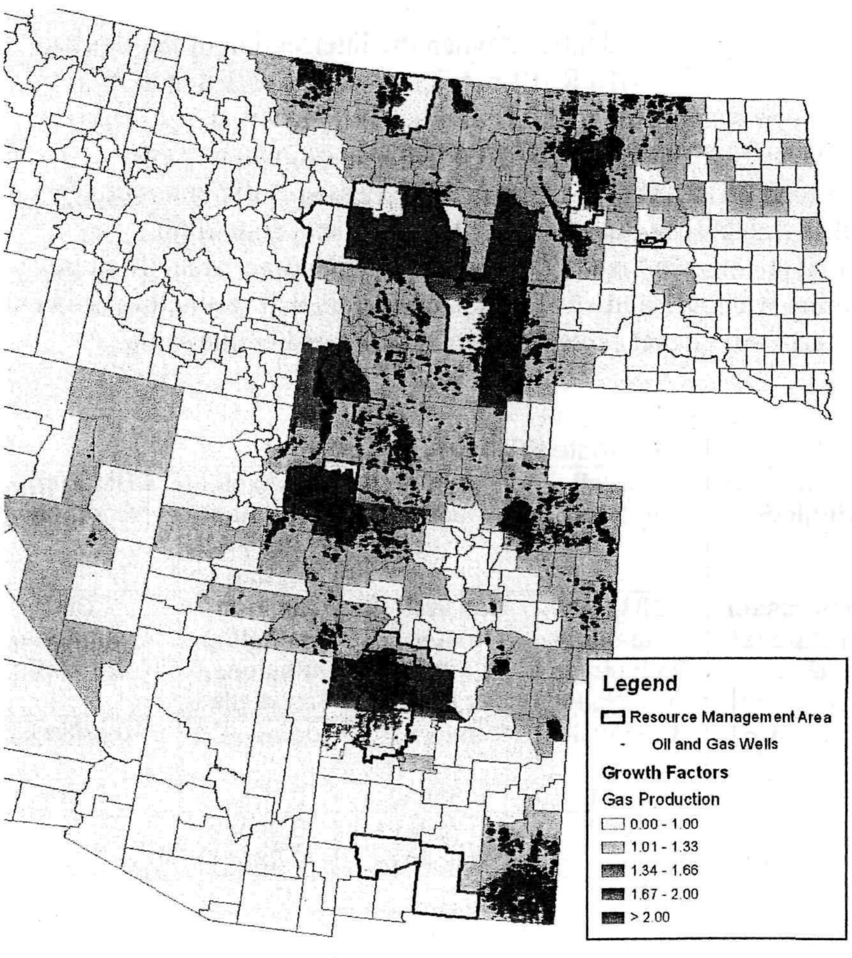


Figure 4-4. Growth factors developed to represent growth in gas production in WRAP region.

Independent 2018 emissions estimates

As is apparent in Figure 4-3, there were some areas where an RMP predicted oil and gas development, but no oil or gas wells existed in 2002. In those cases, the growth factor approach could not be applied. Instead, a method was developed whereby emissions were estimated based on the development forecast by the RMP and the average emissions associated with similar oil and gas sources in the same State. The general form of the calculation used to estimate 2018 emissions in these counties is presented as Calculation 4.

Calculation 4. General formula for independent estimates of 2018 emissions

$$E_{18,P} = D_P * E_{02,P}$$

where:

$E_{18,P}$ = the emissions from a process in 2018
D = the forecast development of process p in the area
$E_{02,P}$ = the state average emissions from process p in 2002

Counties where this method was applied were first identified when the intersection of the RMP areas with counties resulted in the assignment of 2018 RMP-predicted oil, gas, CBM and/or drilled wells to a county that had no such wells in 2002. This number of 2018 oil, gas, CBM and/or drilled wells served as the activity measure for the 2018 emissions estimates. State specific emission factors were derived by dividing 2002 state total process-specific emissions by the number of 2002 oil, gas or drilled wells. In the case of CBM wells, the lack of 2002 emissions in some states required that an emission factor be adopted from another area. In these cases, data from the State of Wyoming were adopted. The emission factors that resulted for NOx are shown in Table 4-8. Emission factors for other pollutants were developed by the same approach.

Table 4-8. State NOx emission factors used to estimate 2018 emissions.

Process	Drill Rigs	Compressor Engines	Oil Well Heaters	Gas Well Heaters	Gas Well Completion Flaring & Venting	CBM Pump Engines
Derivation	**Drill Rig Emissions/ Wells Drilled**	**Compressor Emissions/ Gas Produced**	**Oil Well Heater Emissions /Oil Wells**	**Gas Well Heater Emissions/ Gas Wells**	**Gas Well Completion Emissions/ Gas Wells**	**CBM Emissions/ CBM Wells**
Units	**tons/well drilled**	**tons/MCF**	**tons/well**	**tons/well**	**tons/well**	**tons/well**
Montana	2.26	2.34×10^{-5}	0.011	0.859	0.147	0.12
New Mexico	7.12	2.34×10^{-5}	0.008	0.868	0.046	0.12
North Dakota	9.78	2.34×10^{-5}		0.867	0.031	0.12
Utah	5.37	4.11×10^{-6}	0.015			0.12

Independent 2018 emissions estimates

As is apparent in Figure 4-3, there were some areas where an RMP predicted oil and gas development, but no oil or gas wells existed in 2002. In those cases, the growth factor approach could not be applied. Instead, a method was developed whereby emissions were estimated based on the development forecast by the RMP and the average emissions associated with similar oil and gas sources in the same State. The general form of the calculation used to estimate 2018 emissions in these counties is presented as Calculation 4.

Calculation 4. General formula for independent estimates of 2018 emissions

$$E_{18,P} = D_P * E_{02,P}$$

where:

$E_{18,P}$ = the emissions from a process in 2018
D = the forecast development of process p in the area
$E_{02,P}$ = the state average emissions from process p in 2002

Counties where this method was applied were first identified when the intersection of the RMP areas with counties resulted in the assignment of 2018 RMP-predicted oil, gas, CBM and/or drilled wells to a county that had no such wells in 2002. This number of 2018 oil, gas, CBM and/or drilled wells served as the activity measure for the 2018 emissions estimates. State specific emission factors were derived by dividing 2002 state total process-specific emissions by the number of 2002 oil, gas or drilled wells. In the case of CBM wells, the lack of 2002 emissions in some states required that an emission factor be adopted from another area. In these cases, data from the State of Wyoming were adopted. The emission factors that resulted for NOx are shown in Table 4-8. Emission factors for other pollutants were developed by the same approach.

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Process	Drill Rigs	Compressor Engines	Oil Well Heaters	Gas Well Heaters	Gas Well Completion Flaring & Venting	CBM Pump Engines
Derivation	Drill Rig Emissions/ Wells Drilled	Compressor Emissions/ Gas Produced	Oil Well Heater Emissions /Oil Wells	Gas Well Heater Emissions/ Gas Wells	Gas Well Completion Emissions/ Gas Wells	CBM Emissions/ CBM Wells
Units	tons/well drilled	tons/MCF	tons/well	tons/well	tons/well	tons/well
Montana	2.26	2.34×10^{-5}	0.011	0.859	0.147	0.12
New Mexico	7.12	2.34×10^{-5}	0.008	0.868	0.046	0.12
North Dakota	9.78	2.34×10^{-5}		0.867	0.031	0.12
Utah	5.37	4.11×10^{-6}	0.015			0.12

The emission factors in Table 4-8 were combined with development forecasts as shown in Calculation 4 to produce the county-level emissions shown in Table 4-9. These emissions estimates were then combined with the projected 2018 emissions to produce a comprehensive 2018 area source oil and gas emission inventory.

Table 4-9. 2018 emissions estimates for counties with no 2002 emissions.

State	County	Drill Rigs	Compressor Engines	Wellhead	CBM Pump Engines
Montana	Big Horn	720.45	7,754.11	35.00	119.81
	Golden Valley	7.23	-	-	-
	Mussellshell	124.73	22.42	64.46	-
	Powder River	720.45	7,740.31	-	119.81
	Yellowstone	50.61	10.45	26.49	-
New Mexico	McKinley	67.83	-	-	-
	Otero	9.22	26.74	12.02	-
	Sandoval	35.05	-	-	-
	Sierra	13.83	28.44	12.94	-
North Dakota	Billings	137.76	799.48	213.00	0.15
	Dunn	-	13.70	1.15	0.15
	Golden Valley	8.54	58.42	13.20	0.15
	Slope	7.43	52.03	11.48	0.15
Utah	Daggett	6.21	0.55	0.13	-
	Duschene	-	14.40	-	1.27
	Total	1,909.34	16,521.05	389.87	241.47

Future Year Emission Controls

Implementation of new federal and state control programs will have a substantial impact on future emissions. Known State and Federal emissions control estimates were incorporated into the base case projections for 2018. A summary of the controls that have been identified and the actions taken to incorporate them into the 2018 projections is provided in Table 4-10. These controls add to those previously identified in the 2002 inventory. Thus, although not presented here, the state-specific controls included in the 2002 inventory are adopted by the 2018 inventory. A discussion of the controls identified by the 2002 inventory is provided in Section 2.

Table 4-10. Projection information provided by State DEQ.

State	Future Controls	Action
All	Nonroad diesel engine standards (EPA, 2004)	Used phase-in and emissions standards information for 750+ hp drill rig engines from EPA's NONROAD model to adjust drill rig engine emissions for future performance standards
All	Nonroad spark-ignition engine standards (EPA, 2004)	Used phase-in and emissions standards information for natural gas fired nonroad engines (SCC 2268000000) from EPA's NONROAD model to adjust CBM pump engine emissions for future performance standards

State	Future Controls	Action
Colorado[1]	• 2004, control for glycol dehydrators requiring units in the nonattainment area with greater than 15 tpy VOC emission to achieve 90% control. • 2006, new control of large engines in the Denver-Joulsbourgh Basin NA Area • 2006, new control on condensate tanks requiring VOC emissions in nonattainment area reduced by 47.5% during the VOC season and 38% during off season (CDPHE, 2005)	The following was used as inputs to the procedure used to project point sources: • Determine fraction of dehydrators in nonattainment area and for 2004 and beyond apply 90% control to that fraction. • Select engines with greater than 500 hp and apply 90% control for 2006 and beyond. • Reduce annual VOC emissions from condensate tanks by 43% for 2006 and beyond.
Montana	2006, allow producers to include controls in their potential to emit estimates so that they can stay under 25 tpy and thus not be permitted. DEQ regulation will probably be introduced to require controlling PTE to 25 tpy (MT DEQ, 2005)	No action taken because control requirement has not been promulgated.
Utah	Controls under development with EPA Region 8 (UT DEQ, 2005)	No action taken because control requirements have not been promulgated.

[1]In Colorado, due to the low point source inventory threshold, these control adjustments have been made in the point source inventory

With the exception of the rules imposed in the State of Colorado, the future year controls reported by States were not certain to be implemented and their potential impact was uncertain. In other words, only "on-the-books" controls have been accounted for in this inventory. Due to the low inventory threshold in the State of Colorado, those state-level controls were incorporated in the point source inventory. That left only the federal nonroad engine performance standards to incorporate in this inventory.

After discussion with members of the oil and gas working group, it was determined that the nonroad engine performance standards were applicable to drill rig engines and CBM pump engines, but not to compressor engines. The compressor engine 2018 emissions assume future compressor engines are therefore not required to meet federal nonroad engine standards. In contrast, the 2018 drill rig and CBM pump emissions were adjusted downward under the assumption that future equipment purchases will be required to meet the federal nonroad engine standards. The adjustment for drill rig emissions was performed by comparing the emission rates yielded by EPA's NONROAD model for 750+ horsepower drill rig engines in 2018 versus those for the same category in 2002. For CBM pump engines, the adjustment was performed by comparing the emission rates given by the NONROAD model for natural gas fired engines in 2018 versus those for the same category in 2002. These comparisons were performed on a county level for all WRAP counties and control factors were derived for each county as the 2018 emission rates divided by the 2002 emission rates. The county-level controlled 2018 emissions were then calculated as the product of the county control factor and the uncontrolled 2018 emissions estimate. The emission summaries presented at the beginning of this section represent the comprehensive 2018 oil and gas emissions estimates with "on-the-books" controls.

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Appendix A

Wyoming Emission Factor Documentation

Gas Wells – Completion Emissions from Flaring and Venting

Standardized statewide factors for VOC and HAP emissions associated with flaring and venting activities during gas well completions were created using a weighted average statewide produced gas composition. The averaged analysis indicates VOC and HAP weight percents of 9.43% and 0.33%, respectively

A typical well completion log indicated 5.0 MMCFD of gas are flared and/or vented during 10-days of completion activities. This is the only well completion log available to the Division and is representative of gas well completions in the Pinedale, Wyoming area, where the majority of gas well completions during 2002 occurred.

During well completions, fluids routed to the flares burn when the entrained liquid volumes are low enough. Sometimes the flares are burning basically pure gas, while other times the flares don't or won't ignite when liquid volumes are excessive. Since typical volumes of gas and liquid routed to a completion flare are not known, 50% of the time for each situation is assumed.

During flaring of completion gas, different opacity levels have been observed, ranging from 0 to 100%. This indicates completion fluids are not 100% combusted. Sometimes well flares smoke excessively and sometimes they burn clean, depending on the amount of liquids entrained in the flared vapors. To account for this, 50% destruction efficiency of flares for VOCs and HAPs are assumed.

Emissions associated with gas venting are calculated as follows:

(5 MMCF/day) × (18.4565 lb/lb-mol) × (lb-mol/379 scf) × (10^6 scf/MMCF) × (ton/2000 lb)
= 121.7447 tons of total gas flared or vented per day per completion

121.7447 tons of gas per day × 10 days = 1217.4472 tons of gas per completion

1217.4472 total tons × 0.0943 wt% VOC = 114.8053 total tons VOC

50% of 114.8053 tons VOC are vented = 57.4027 tons VOC vented per completion

50% of 114.8053 tons VOC are flared w/ 50% destruction efficiency
= 28.7013 tons VOC from incomplete combustion per completion

Total VOC from flaring/venting = 86.0 tons per well completion

1217.4472 total tons × 0.0033 wt% HAP = 4.0176 total tons HAP

50% of 4.0176 tons HAP are vented = 2.0088 tons HAP vented per completion

50% of 4.0176 tons HAP are flared w/ 50% destruction efficiency
= 1.0044 tons HAP from incomplete combustion per completion

Gas Wells – Completion Emissions from Flaring and Venting cont'd

Total HAP from flaring/venting = 3.0 tons per well completion

0.6087 total tons Benzene @ 50% vented/50% flared = **0.5 tons Benzene per well/completion**
1.0957 total tons Toluene @ 50% vented/50% flared = **0.7 tons Toluene per well/completion**
0.3652 total tons Xylene @ 50% vented/50% flared = **0.8 tons Xylene per well/completion**
1.9479 total tons n-C^6 @ 50% vented/50% flared = **1.3 tons n-C^6 per well/completion**
undetectable e-Benzene

For NO_X and CO emissions from flaring, AP-42 flare emission factors were used as follows:

(5.0 MMCF/day) × (0.14 lb NO_X/MMBtu) × (1000 Btu/SCF) × (10^6 SCF/MMCF) × (MMBtu/10^6 Btu) × (ton/2000 lb) = 0.35 tons NO_X per day.

Using the same calculate with 0.035 lb CO/MMCF = 0.0875 tons CO per day

Assuming gas wells are flared 50% of the time during 10 days of completion operations flaring emissions are:

1.75 tons NO_X & 0.44 tons CO per gas well completion

VOC and HAP emissions from pneumatic devices at gas and oil well facilities

The average pneumatic pump uses and emits approximately 5.0 SCF/hr. These pumps are to inject methanol into flowlines and equipment at oil and gas well facilities. Most gas wells have two associated pneumatic injection pumps. Most oil wells have one associated pneumatic pump. Each type of well has various other pneumatic devices.

VOC and HAP emission from pneumatic pumps are calculated using the statewide average weighted gas composition, 5.0 SCF/hr gas usage, two pumps per gas well and one pump per oil well, as follows:

(5 SCF/hr) × (18.4565 lb/lb-mol) × (lb-mol/379 SCF) × (8760 hr/yr) (ton/2000 lb)
= 1.07 tons gas used per year per pump

1.07 tons × 0.0943 wt% VOC = 0.1 tons VOC per year/pump

1.07 tons × 0.0033 wt% HAP = 0.004 tons HAP per year/pump

For each gas well pneumatic emissions are 0.2 tons VOC/yr/well and 0.008 tons HAP/yr/well

For each oil well pneumatic emissions are 0.1 tons VOC/yr/well and 0.004 tons HAP/yr/well

VOC and HAP emissions from other pneumatic devices at each oil and gas well are typically less than 1.0 TPY VOC and less than 0.1 TPY HAP.

Gas Wells – Flashing & Standing/Working/Breathing VOC Emissions

Standardized statewide emission factors for storage tank emissions were created by calculating the average compositions of condensate for each formation for which analyses were available. These averages were used to formulate a weighted average for condensate composition across the state, based on production per formation. The weighted average was used with E&P Tanks modeling software to calculate emission factors in tons per year (TPY) per barrel per day (BPD) of condensate production.

The calculations yielded emissions of 3,271.0 pounds per year (1.64 TPY) of VOCs per BPD and 116.0 pounds per year (0.06 TPY) of HAPs per BPD uncontrolled. For wells that produce above 18.3 BPD of condensate controls would be installed, since the VOC emission would be above the 30.0 TPY threshold used in 2002. The emission factors would then be 65.74 pounds per year (0.03 TPY) of VOCs per BPD and 2.32 pounds per year (0.001 TPY) of HAPs per BPD controlled with 98% efficiency.

Uncontrolled	**Controlled**
Benzene = 31.4 lb per yr/BPD	Benzene = 0.63 lb per yr/BPD
Toluene = 0.8 lb per yr/BPD	Toluene = 0.02 lb per yr/BPD
Ethyl benzene = 2.6 lb per yr/BPD	Ethyl benzene = 0.05 lb per yr/BPD
Xylenes = 1.8 lb per yr/BPD	Xylenes = 0.04 lb per yr/BPD
n-Hexane = 7.8 lb per yr/BPD	n-Hexane = 0.16 lb per yr/BPD

Gas Wells – Dehydration Unit VOC & HAP Emissions

Standardized statewide emission factors for dehydration unit emissions were created by calculating the average compositions of wet gas for each formation for which analyses were available. These averages were used to formulate a weighted average for gas composition across the state, based on production per formation. The weighted average was then used with GRI GlyCalc modeling software to calculate emission factors based on one million standard cubic foot of gas per day (MSCFD) at 0.425 gpm or 25.0 spm for a Kimray 4015 glycol pump. 25.0 spm is an observed average pump rate and the Kimray 4015 model is the most widely used.

The calculations yielded emissions of 27,485.6 pounds per year (13.74 TPY) of VOCs per 10^6 cubic feet per day (MMCFD) and 13,695.6 pounds per year (6.85 TPY) of HAPs per MMCFD.

Benzene = 3,019.0 lb per yr/MMCFD
Toluene = 6,944.2 lb per yr/MMCFD
Ethyl benzene = 288.8 lb per yr/MMCFD
Xylenes = 3,054.8 lb per yr/MMCFD
n-Hexane = 361.0 lb per yr/MMCFD

Gas Wells – Heater Emissions

For an average gas well site, approximately 2.0 MMBtu/hr are used in all of the different heaters and burners. The average heat content of the fuel used in these heaters is estimated at 1000 Btu/scf. This activity results in 1,752.0 pounds per year (0.88 TPY) of NOx and 367.92 pounds per year (0.18 TPY) of CO for each gas well installation. These were calculated using AP-42 emission factors for fuel boilers and heaters, 100 lb/mmcf for NOx and 21 lb/mmcf for CO.

Oil Wells – Flashing & Standing/Working/Breathing VOC Emissions

Statewide standardized emission factors for storage tank emissions were formulated using the geographical database built into E&P Tanks emissions modeling software. The data gathered for sales oil with an API Gravity of 30.0 and Reid Vapor Pressure of 2.7 psia was selected as it most closely approximates the majority of Wyoming crude oil. The resulting factors in pounds of emissions per year per BPD oil production at individual wells:

VOCs = 160.0 lb per yr/BPD
HAPs = 2.66 lb per yr/BPD
Benzene = 0.014 lb per yr/BPD
Toluene = 0.018 lb per yr/BPD
Ethyl Benzene = 0.004 lb per yr/BPD
Xylenes = 0.034 lb per yr/BPD
n-Hexane = 2.598 lb per yr/BPD

Oil Wells – Heater Emissions

In Wyoming, most oil wells are produced to a central battery where various heated vessels are used for separation of crude and water. An average throughput of 2000 barrels per day at a facility using 4.0 MMBtu/hr total heat input was used along with AP-42 emission factors for fuel boilers and heaters to estimate 0.005 pounds per year of NO_X per BPD and 0.001 pounds per yr of CO per BPD of oil production at each individual oil well [later corrected units to 0.005 pounds per year of NOx per barrel and 0.001 pounds per year of CO per barrel].

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Appendix A

Wyoming Emission Factor Documentation

Gas Wells – Completion Emissions from Flaring and Venting

Standardized statewide factors for VOC and HAP emissions associated with flaring and venting activities during gas well completions were created using a weighted average statewide produced gas composition. The averaged analysis indicates VOC and HAP weight percents of 9.43% and 0.33%, respectively

A typical well completion log indicated 5.0 MMCFD of gas are flared and/or vented during 10-days of completion activities. This is the only well completion log available to the Division and is representative of gas well completions in the Pinedale, Wyoming area, where the majority of gas well completions during 2002 occurred.

During well completions, fluids routed to the flares burn when the entrained liquid volumes are low enough. Sometimes the flares are burning basically pure gas, while other times the flares don't or won't ignite when liquid volumes are excessive. Since typical volumes of gas and liquid routed to a completion flare are not known, 50% of the time for each situation is assumed.

During flaring of completion gas, different opacity levels have been observed, ranging from 0 to 100%. This indicates completion fluids are not 100% combusted. Sometimes well flares smoke excessively and sometimes they burn clean, depending on the amount of liquids entrained in the flared vapors. To account for this, 50% destruction efficiency of flares for VOCs and HAPs are assumed.

Emissions associated with gas venting are calculated as follows:

(5 MMCF/day) × (18.4565 lb/lb-mol) × (lb-mol/379 scf) × (10^6 scf/MMCF) × (ton/2000 lb)
= 121.7447 tons of total gas flared or vented per day per completion

121.7447 tons of gas per day × 10 days = 1217.4472 tons of gas per completion

1217.4472 total tons × 0.0943 wt% VOC = 114.8053 total tons VOC

50% of 114.8053 tons VOC are vented = 57.4027 tons VOC vented per completion

50% of 114.8053 tons VOC are flared w/ 50% destruction efficiency
= 28.7013 tons VOC from incomplete combustion per completion

Total VOC from flaring/venting = 86.0 tons per well completion

1217.4472 total tons × 0.0033 wt% HAP = 4.0176 total tons HAP

50% of 4.0176 tons HAP are vented = 2.0088 tons HAP vented per completion

50% of 4.0176 tons HAP are flared w/ 50% destruction efficiency
= 1.0044 tons HAP from incomplete combustion per completion

Gas Wells – Completion Emissions from Flaring and Venting cont'd

Total HAP from flaring/venting = 3.0 tons per well completion

0.6087 total tons Benzene @ 50% vented/50% flared = **0.5 tons Benzene per well/completion**
1.0957 total tons Toluene @ 50% vented/50% flared = **0.7 tons Toluene per well/completion**
0.3652 total tons Xylene @ 50% vented/50% flared = **0.8 tons Xylene per well/completion**
1.9479 total tons n-C^6 @ 50% vented/50% flared = **1.3 tons n-C^6 per well/completion**
undetectable e-Benzene

For NO_X and CO emissions from flaring, AP-42 flare emission factors were used as follows:

(5.0 MMCF/day) × (0.14 lb NO_X/MMBtu) × (1000 Btu/SCF) × (10^6 SCF/MMCF) × (MMBtu/10^6 Btu) × (ton/2000 lb) = 0.35 tons NO_X per day.

Using the same calculate with 0.035 lb CO/MMCF = 0.0875 tons CO per day

Assuming gas wells are flared 50% of the time during 10 days of completion operations flaring emissions are:

1.75 tons NO_X & 0.44 tons CO per gas well completion

VOC and HAP emissions from pneumatic devices at gas and oil well facilities

The average pneumatic pump uses and emits approximately 5.0 SCF/hr. These pumps are to inject methanol into flowlines and equipment at oil and gas well facilities. Most gas wells have two associated pneumatic injection pumps. Most oil wells have one associated pneumatic pump. Each type of well has various other pneumatic devices.

VOC and HAP emission from pneumatic pumps are calculated using the statewide average weighted gas composition, 5.0 SCF/hr gas usage, two pumps per gas well and one pump per oil well, as follows:

(5 SCF/hr) × (18.4565 lb/lb-mol) × (lb-mol/379 SCF) × (8760 hr/yr) (ton/2000 lb)
= 1.07 tons gas used per year per pump

1.07 tons × 0.0943 wt% VOC = 0.1 tons VOC per year/pump

1.07 tons × 0.0033 wt% HAP = 0.004 tons HAP per year/pump

For each gas well pneumatic emissions are 0.2 tons VOC/yr/well and 0.008 tons HAP/yr/well

For each oil well pneumatic emissions are 0.1 tons VOC/yr/well and 0.004 tons HAP/yr/well

VOC and HAP emissions from other pneumatic devices at each oil and gas well are typically less than 1.0 TPY VOC and less than 0.1 TPY HAP.

Gas Wells – Flashing & Standing/Working/Breathing VOC Emissions

Standardized statewide emission factors for storage tank emissions were created by calculating the average compositions of condensate for each formation for which analyses were available. These averages were used to formulate a weighted average for condensate composition across the state, based on production per formation. The weighted average was used with E&P Tanks modeling software to calculate emission factors in tons per year (TPY) per barrel per day (BPD) of condensate production.

The calculations yielded emissions of 3,271.0 pounds per year (1.64 TPY) of VOCs per BPD and 116.0 pounds per year (0.06 TPY) of HAPs per BPD uncontrolled. For wells that produce above 18.3 BPD of condensate controls would be installed, since the VOC emission would be above the 30.0 TPY threshold used in 2002. The emission factors would then be 65.74 pounds per year (0.03 TPY) of VOCs per BPD and 2.32 pounds per year (0.001 TPY) of HAPs per BPD controlled with 98% efficiency.

Uncontrolled
Benzene = 31.4 lb per yr/BPD
Toluene = 0.8 lb per yr/BPD
Ethyl benzene = 2.6 lb per yr/BPD
Xylenes = 1.8 lb per yr/BPD
n-Hexane = 7.8 lb per yr/BPD

Controlled
Benzene = 0.63 lb per yr/BPD
Toluene = 0.02 lb per yr/BPD
Ethyl benzene = 0.05 lb per yr/BPD
Xylenes = 0.04 lb per yr/BPD
n-Hexane = 0.16 lb per yr/BPD

Gas Wells – Dehydration Unit VOC & HAP Emissions

Standardized statewide emission factors for dehydration unit emissions were created by calculating the average compositions of wet gas for each formation for which analyses were available. These averages were used to formulate a weighted average for gas composition across the state, based on production per formation. The weighted average was then used with GRI GlyCalc modeling software to calculate emission factors based on one million standard cubic foot of gas per day (MSCFD) at 0.425 gpm or 25.0 spm for a Kimray 4015 glycol pump. 25.0 spm is an observed average pump rate and the Kimray 4015 model is the most widely used.

The calculations yielded emissions of 27,485.6 pounds per year (13.74 TPY) of VOCs per 10^6 cubic feet per day (MMCFD) and 13,695.6 pounds per year (6.85 TPY) of HAPs per MMCFD.

Benzene = 3,019.0 lb per yr/MMCFD
Toluene = 6,944.2 lb per yr/MMCFD
Ethyl benzene = 288.8 lb per yr/MMCFD
Xylenes = 3,054.8 lb per yr/MMCFD
n-Hexane = 361.0 lb per yr/MMCFD

Gas Wells – Heater Emissions

For an average gas well site, approximately 2.0 MMBtu/hr are used in all of the different heaters and burners. The average heat content of the fuel used in these heaters is estimated at 1000 Btu/scf. This activity results in 1,752.0 pounds per year (0.88 TPY) of NOx and 367.92 pounds per year (0.18 TPY) of CO for each gas well installation. These were calculated using AP-42 emission factors for fuel boilers and heaters, 100 lb/mmcf for NOx and 21 lb/mmcf for CO.

Oil Wells – Flashing & Standing/Working/Breathing VOC Emissions

Statewide standardized emission factors for storage tank emissions were formulated using the geographical database built into E&P Tanks emissions modeling software. The data gathered for sales oil with an API Gravity of 30.0 and Reid Vapor Pressure of 2.7 psia was selected as it most closely approximates the majority of Wyoming crude oil. The resulting factors in pounds of emissions per year per BPD oil production at individual wells:

VOCs = 160.0 lb per yr/BPD
HAPs = 2.66 lb per yr/BPD
Benzene = 0.014 lb per yr/BPD
Toluene = 0.018 lb per yr/BPD
Ethyl Benzene = 0.004 lb per yr/BPD
Xylenes = 0.034 lb per yr/BPD
n-Hexane = 2.598 lb per yr/BPD

Oil Wells – Heater Emissions

In Wyoming, most oil wells are produced to a central battery where various heated vessels are used for separation of crude and water. An average throughput of 2000 barrels per day at a facility using 4.0 MMBtu/hr total heat input was used along with AP-42 emission factors for fuel boilers and heaters to estimate 0.005 pounds per year of NO_X per BPD and 0.001 pounds per yr of CO per BPD of oil production at each individual oil well [later corrected units to 0.005 pounds per year of NOx per barrel and 0.001 pounds per year of CO per barrel].

Appendix B

Sample Calculations for the VOC and Minor NOx Processes

Sample Calculation for Gas Well

Well Name = 476
Well Type = Gas
Field Name = Five Mile
County = Big Horn
2002 Gas Production (GP) = 193,559 1000CF
2002 Condensate Production (CP) = 2,968 barrels
Completion Date = 6/25/2002

Calculate approximate number of operational days per year
Number of days June - December = 214 well days per year (wdpy)

Flashing & Standing/Working/Breathing Emissions
Will there be controls on flashing & standing/working/breathing?
CP / wdpy <= 18.3
2,968 barrels / 214 wdpy <= 18.3
13.9 <= 18.3 therefore there will be no controls
VOC EF = 3,271 lbs/yr per BPD CP
Benzene EF = 31.4 lbs/yr per BPD CP

Annual VOC = CP / wdpy * VOC EF / 2000 lb/ton * wdpy / total dpy
Annual VOC = 2,968 barrels / 214 wdpy * 3,271 lbs/yr per BPD CP / 2000 lb/ton * 214 wdpy / 365 dpy
Annual VOC = 13.9 bpd * 3,271 lbs/yr per BPD CP / 2000 lb/ton * .586
Annual VOC = 13.3 tons

Annual Benzene = CP / wdpy * Benzene EF / 2000 lb/ton * wdpy / total dpy
Annual Benzene = 13.9 bpd * 31.4 lbs/yr per BPD CP / 2000 lb/ton * .586
Annual Benzene = .13 tons

Dehydration Unit Emissions
VOC EF = 27,485.6 lbs per year / MCFD
Annual VOC = VOC EF * GP / 1000 MCF/1000CF / 214 wdpy / 2000 lb/ton * 214 wdpy / 365 dpy
Annual VOC = 27,485.6 lbs per year / MCFD * 193.6MCF / 214 wdpy / 2000 lb/ton * .586
Annual VOC = 7.3 tons

Heater Emissions
NOx EF = 1,752 lbs / year - well
Annual NOx = NOX EF * Number of Wells / 2000 lb/ton * wdpy / dpy
Annual NOx = 1,752 lbs / year-well * 1 well / 2000 lb/ton * .586
Annual NOx = .51 tons

Pneumatic Devices

VOC EF = .2 tons / year-well
Annual VOC = VOC EF * Number of Wells * wdpy / dpy
Annual VOC = .2 tons / year-well * 1 well * .586
Annual VOC = .12 tons

Completion Flaring and Venting

VOC EF = 86 tons / completion
Annual VOC = completions * VOC EF
Annual VOC = 1 completion * 86 tons / completion
Annual VOC = 86 tons

These sample calculations only present the calculation for one pollutant for each process. The calculations for other pollutants within the same process were identical, with the exception of the emission factor.

Sample Calculation for Oil Well

Well Name = 483
Well Type = Oil
Field Name = Torchlight
County = Big Horn
2002 Oil Production (OP) = 8,758 barrels
Completion Date = 2/4/2002

Calculate approximate number of operational days per year

Number of days February - December = 334 well days per year (wdpy)

Flashing & Standing/Working/Breathing Emissions

VOC EF = 160 lb/year per BPD OP
Annual VOC = VOC EF * OP / wdpy / 2000 lb/ton * wdpy / dpy
Annual VOC = 160 lb/year per BPD OP * 8,758 barrels / 334 wdpy / 2000 lb/ton * 334 wdpy / 365 dpy
Annual VOC = 160 lb/year per BPD OP * 26.2 BPD / 2000 lb/ton * .915
Annual VOC = 1.92 tons

Heater

NOx EF = 0.005 lb/yr per BPD OP
Annual NOx = NOx EF * OP / wdpy / 2000 lb/ton * wdpy / dpy
Annual NOx = 0.005 lb/yr per BPD OP * 26.2 BPD / 2000 lb/ton * .915
Annual NOx = 0.00006 tons

Pneumatic Devices

VOC EF = 0.10 tons/yr per well
Annual VOC = VOC EF * Number of Wells * wdpy / dpy
Annual VOC = 0.10 tons/yr per well * 1 well * .915
Annual VOC = 0.092 tons

Appendix C

Nonroad Diesel Fuel Sulfur Levels

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
02013	0.075	08071	0.050	30013	0.240
02016	0.075	08073	0.050	30015	0.240
02020	0.119	08075	0.050	30017	0.240
02050	0.075	08077	0.050	30019	0.240
02060	0.075	08079	0.050	30021	0.240
02068	0.075	08081	0.050	30023	0.240
02070	0.075	08083	0.050	30025	0.240
02090	0.119	08085	0.050	30027	0.240
02100	0.035	08087	0.050	30029	0.240
02110	0.035	08089	0.050	30031	0.240
02122	0.119	08091	0.050	30033	0.240
02130	0.035	08093	0.050	30035	0.240
02150	0.075	08095	0.050	30037	0.240
02164	0.075	08097	0.050	30039	0.240
02170	0.119	08099	0.050	30041	0.240
02180	0.075	08101	0.050	30043	0.240
02185	0.075	08103	0.050	30045	0.240
02188	0.075	08105	0.050	30047	0.240
02201	0.035	08107	0.050	30049	0.240
02220	0.035	08109	0.050	30051	0.240
02232	0.035	08111	0.050	30053	0.240
02240	0.119	08113	0.050	30055	0.240
02261	0.119	08115	0.050	30057	0.240
02270	0.075	08117	0.050	30059	0.240
02280	0.035	08119	0.050	30061	0.240
02282	0.075	08121	0.050	30063	0.240
02290	0.075	08123	0.050	30065	0.240
04001	0.240	08125	0.050	30067	0.240
04003	0.240	16001	0.330	30069	0.240
04005	0.340	16003	0.330	30071	0.240
04007	0.340	16005	0.330	30073	0.240
04009	0.240	16007	0.330	30075	0.240
04011	0.240	16009	0.330	30077	0.240
04012	0.340	16011	0.330	30079	0.240
04013	0.036	16013	0.330	30081	0.240
04015	0.340	16015	0.330	30083	0.240
04017	0.240	16017	0.330	30085	0.240
04019	0.340	16019	0.330	30087	0.240
04021	0.340	16021	0.330	30089	0.240
04023	0.240	16023	0.330	30091	0.240
04025	0.340	16025	0.330	30093	0.240
04027	0.340	16027	0.330	30095	0.240
08001	0.050	16029	0.330	30097	0.240
08003	0.050	16031	0.330	30099	0.240
08005	0.050	16033	0.330	30101	0.240
08007	0.050	16035	0.330	30103	0.240

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
08009	0.050	16037	0.330	30105	0.240
08011	0.050	16039	0.330	30107	0.240
08013	0.050	16041	0.330	30109	0.240
08014	0.050	16043	0.330	30111	0.240
08015	0.050	16045	0.330	30113	0.240
08017	0.050	16047	0.330	32001	0.050
08019	0.050	16049	0.330	32003	0.025
08021	0.050	16051	0.330	32005	0.050
08023	0.050	16053	0.330	32007	0.050
08025	0.050	16055	0.330	32009	0.050
08027	0.050	16057	0.330	32011	0.050
08029	0.050	16059	0.330	32013	0.050
08031	0.050	16061	0.330	32015	0.050
08033	0.050	16063	0.330	32017	0.025
08035	0.050	16065	0.330	32019	0.050
08037	0.050	16067	0.330	32021	0.050
08039	0.050	16069	0.330	32023	0.025
08041	0.050	16071	0.330	32027	0.050
08043	0.050	16073	0.330	32029	0.050
08045	0.050	16075	0.330	32031	0.050
08047	0.050	16077	0.330	32033	0.050
08049	0.050	16079	0.330	32510	0.050
08051	0.050	16081	0.330	35001	0.240
08053	0.050	16083	0.330	35003	0.240
08055	0.050	16085	0.330	35005	0.240
08057	0.050	16087	0.330	35006	0.240
08059	0.050	30001	0.240	35007	0.240
08061	0.050	30003	0.240	35009	0.240
08063	0.050	30005	0.240	35011	0.240
08065	0.050	30007	0.240	35013	0.240
08067	0.050	30009	0.240	35015	0.240
08069	0.050	30011	0.240	35017	0.240

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
35019	0.240	41007	0.340	46095	0.371
35021	0.240	41009	0.340	46097	0.371
35023	0.240	41011	0.340	46099	0.371
35025	0.240	41013	0.340	46101	0.371
35027	0.240	41015	0.340	46103	0.240
35028	0.240	41017	0.340	46105	0.240
35029	0.240	41019	0.340	46107	0.371
35031	0.240	41021	0.340	46109	0.371
35033	0.240	41023	0.340	46111	0.371
35035	0.240	41025	0.340	46113	0.240
35037	0.240	41027	0.340	46115	0.371
35039	0.240	41029	0.340	46117	0.371
35041	0.240	41031	0.340	46119	0.371
35043	0.240	41033	0.340	46121	0.371
35045	0.240	41035	0.340	46123	0.371
35047	0.240	41037	0.340	46125	0.371
35049	0.240	41039	0.340	46127	0.371
35051	0.240	41041	0.340	46129	0.371
35053	0.240	41043	0.340	46135	0.371
35055	0.240	41045	0.340	46137	0.371
35057	0.240	41047	0.340	49001	0.340
35059	0.240	41049	0.340	49003	0.240
35061	0.240	41051	0.340	49005	0.240
38001	0.240	41053	0.340	49007	0.240
38003	0.371	41055	0.340	49009	0.240
38005	0.371	41057	0.340	49011	0.240
38007	0.240	41059	0.340	49013	0.240
38009	0.371	41061	0.340	49015	0.240
38011	0.240	41063	0.340	49017	0.340
38013	0.240	41065	0.340	49019	0.240
38015	0.371	41067	0.340	49021	0.340
38017	0.371	41069	0.340	49023	0.240
38019	0.371	41071	0.340	49025	0.340
38021	0.371	46003	0.371	49027	0.240
38023	0.240	46005	0.371	49029	0.240
38025	0.240	46007	0.371	49031	0.340
38027	0.371	46009	0.371	49033	0.240
38029	0.371	46011	0.371	49035	0.240
38031	0.371	46013	0.371	49037	0.240
38033	0.240	46015	0.371	49039	0.240
38035	0.371	46017	0.371	49041	0.240
38037	0.371	46019	0.240	49043	0.240
38039	0.371	46021	0.371	49045	0.240
38041	0.240	46023	0.371	49047	0.240
38043	0.371	46025	0.371	49049	0.240
38045	0.371	46027	0.371	49051	0.240

County FIPs	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)	County FIPs (cont.)	Fuel Diesel Sulfur (%)
38047	0.371	46029	0.371	49053	0.340
38049	0.371	46031	0.371	49055	0.240
38051	0.371	46033	0.240	49057	0.240
38053	0.240	46035	0.371	53001	0.340
38055	0.371	46037	0.371	53003	0.340
38057	0.371	46039	0.371	53005	0.340
38059	0.371	46041	0.371	53007	0.340
38061	0.240	46043	0.371	53009	0.340
38063	0.371	46045	0.371	53011	0.340
38065	0.371	46047	0.240	53013	0.340
38067	0.371	46049	0.371	53015	0.340
38069	0.371	46051	0.371	53017	0.340
38071	0.371	46053	0.371	53019	0.340
38073	0.371	46055	0.371	53021	0.340
38075	0.371	46057	0.371	53023	0.340
38077	0.371	46059	0.371	53025	0.340
38079	0.371	46061	0.371	53027	0.340
38081	0.371	46063	0.240	53029	0.340
38083	0.371	46065	0.371	53031	0.340
38085	0.371	46067	0.371	53033	0.340
38087	0.240	46069	0.371	53035	0.340
38089	0.240	46071	0.371	53037	0.340
38091	0.371	46073	0.371	53039	0.340
38093	0.371	46075	0.371	53041	0.340
38095	0.371	46077	0.371	53043	0.340
38097	0.371	46079	0.371	53045	0.340
38099	0.371	46081	0.240	53047	0.340
38101	0.371	46083	0.371	53049	0.340
38103	0.371	46085	0.371	53051	0.340
38105	0.240	46087	0.371	53053	0.340
41001	0.340	46089	0.371	53055	0.340
41003	0.340	46091	0.371	53057	0.340
41005	0.340	46093	0.240	53059	0.340

County FIPs	Fuel Diesel Sulfur (%)
53061	0.340
53063	0.340
53065	0.340
53067	0.340
53069	0.340
53071	0.340
53073	0.340
53075	0.340
53077	0.340
56001	0.270
56003	0.270
56005	0.270
56007	0.270
56009	0.270
56011	0.270
56013	0.270
56015	0.270
56017	0.270
56019	0.270
56021	0.270
56023	0.270
56025	0.270
56027	0.270
56029	0.270
56031	0.270
56033	0.270
56035	0.270
56037	0.270
56039	0.270
56041	0.270
56043	0.270
56045	0.270

Appendix D

2002 to 2018 Oil and Gas Growth Factors

SCC	FIPS	Growth Factor
2310000220	00000	4.4368
2310000220	02020	0.0000
2310000220	02122	1.0000
2310000220	02185	1.0000
2310000220	08001	1.0710
2310000220	08007	1.0580
2310000220	08009	1.0710
2310000220	08014	1.0710
2310000220	08017	1.0710
2310000220	08045	1.0614
2310000220	08051	1.0710
2310000220	08055	1.0710
2310000220	08057	1.0710
2310000220	08061	1.0710
2310000220	08067	1.1138
2310000220	08071	1.0710
2310000220	08073	1.0710
2310000220	08075	1.0710
2310000220	08077	1.0710
2310000220	08081	1.0582
2310000220	08083	1.0710
2310000220	08087	1.0710
2310000220	08099	1.0710
2310000220	08103	1.5108
2310000220	08107	1.0710
2310000220	08113	1.0710
2310000220	08121	1.0710
2310000220	08123	1.0710
2310000220	08125	1.0710
2310000220	30003	39.4556
2310000220	30005	0.1202
2310000220	30009	129.8828
2310000220	30011	1.0710
2310000220	30015	1.0710
2310000220	30017	8.2123
2310000220	30019	1.0710
2310000220	30021	1.0710
2310000220	30025	1.0710
2310000220	30027	1.0710
2310000220	30035	1.0710
2310000220	30041	1.0710
2310000220	30045	1.0710
2310000220	30051	1.0710
2310000220	30055	1.0710
2310000220	30065	85.3516
2310000220	30069	1.0710
2310000220	30071	1.0710
2310000220	30073	1.0710
2310000220	30075	76.3745
2310000220	30079	1.0710
2310000220	30083	1.0710
2310000220	30085	1.0710
2310000220	30087	1.0710
2310000220	30091	1.0710
2310000220	30095	12.3698
2310000220	30097	2.4740
2310000220	30101	1.0710
2310000220	30105	1.0710
2310000220	30111	34.6354
2310000220	32007	1.0710
2310000220	32011	1.0710
2310000220	32023	1.0710
2310000220	35005	1.0710
2310000220	35007	1.0710
2310000220	35015	1.0710
2310000220	35025	1.0710
2310000220	35039	2.6956
2310000220	35041	1.0710
2310000220	35045	2.6596
2310000220	35059	1.0710
2310000220	38007	2.8811
2310000220	38009	1.0710
2310000220	38011	1.0710
2310000220	38013	1.0710
2310000220	38023	1.0710
2310000220	38025	1.0889
2310000220	38033	0.9604
2310000220	38035	1.0710
2310000220	38049	1.0710
2310000220	38053	2.1276
2310000220	38059	1.0710
2310000220	38075	1.0710
2310000220	38087	0.1172
2310000220	38089	1.0710
2310000220	38093	1.0710
2310000220	38103	1.0710
2310000220	38105	1.0710
2310000220	46047	1.0710
2310000220	46063	1.0710
2310000220	49007	1.0710
2310000220	49013	5.1715
2310000220	49015	1.0710
2310000220	49019	1.0710
2310000220	49037	1.0710
2310000220	49047	8.7089
2310000220	56001	1.0710
2310000220	56003	1.0710
2310000220	56005	2.2528
2310000220	56007	1.1995
2310000220	56009	24.1974
2310000220	56011	1.0710
2310000220	56013	1.0710
2310000220	56017	1.0710
2310000220	56019	0.7792
2310000220	56023	1.3425
2310000220	56025	1.0710
2310000220	56027	1.0710
2310000220	56029	1.0710
2310000220	56033	1.5976
2310000220	56035	3.8028
2310000220	56037	1.1577
2310000220	56041	1.0710
2310010100	00000	1.2753
2310010100	08001	1.3340
2310010100	08005	1.3340
2310010100	08007	1.0022
2310010100	08009	1.3340
2310010100	08013	1.3340
2310010100	08017	1.3340
2310010100	08033	1.3340
2310010100	08039	1.3340
2310010100	08043	1.3340
2310010100	08045	1.3300
2310010100	08057	1.3340
2310010100	08061	1.3340
2310010100	08063	1.3340
2310010100	08067	1.3307
2310010100	08069	1.3340
2310010100	08073	1.3340
2310010100	08075	1.3340
2310010100	08077	1.3340
2310010100	08081	1.3253

SCC	FIPS	Growth Factor
2310010100	08083	1.3340
2310010100	08087	1.3340
2310010100	08099	1.3340
2310010100	08103	0.9979
2310010100	08107	1.3340
2310010100	08113	1.3340
2310010100	08115	1.3340
2310010100	08121	1.3340
2310010100	08123	1.3340
2310010100	30003	0.9649
2310010100	30005	0.9899
2310010100	30009	0.9746
2310010100	30019	1.3340
2310010100	30021	1.3340
2310010100	30025	1.3340
2310010100	30033	1.3340
2310010100	30035	1.3340
2310010100	30041	1.3340
2310010100	30051	1.3340
2310010100	30055	1.3340
2310010100	30065	0.9227
2310010100	30069	1.3340
2310010100	30073	1.3340
2310010100	30075	1.0000
2310010100	30079	1.3340
2310010100	30083	1.3340
2310010100	30085	1.3340
2310010100	30087	1.3340
2310010100	30091	1.3340
2310010100	30095	0.8333
2310010100	30099	1.3340
2310010100	30101	1.3340
2310010100	30105	1.3340
2310010100	30109	1.3340
2310010100	30111	1.0000
2310010100	32011	1.3340
2310010100	32023	1.3340
2310010100	35005	0.8660
2310010100	35015	0.8660
2310010100	35025	0.8660
2310010100	35031	0.9953
2310010100	35039	1.2786
2310010100	35041	0.8660
2310010100	35043	1.0263
2310010100	35045	1.7402
2310010100	38007	1.0336
2310010100	38009	1.3340
2310010100	38011	1.3340
2310010100	38013	1.3340
2310010100	38023	1.3340
2310010100	38025	1.3268
2310010100	38033	1.1452
2310010100	38041	1.3340
2310010100	38049	1.3340
2310010100	38053	1.1667
2310010100	38055	1.3340
2310010100	38061	1.3340
2310010100	38075	1.3340
2310010100	38087	0.9789
2310010100	38089	1.3340
2310010100	38101	1.3340
2310010100	38105	1.3340
2310010100	46041	1.3340
2310010100	46047	1.3340
2310010100	46063	1.3340
2310010100	49013	1.6365
2310010100	49015	1.3340
2310010100	49017	1.3340
2310010100	49019	1.3340
2310010100	49037	1.3340
2310010100	49043	1.3340
2310010100	49047	3.8530
2310010100	56001	1.3340
2310010100	56003	1.3340
2310010100	56005	0.9965
2310010100	56007	1.2974
2310010100	56009	1.0727
2310010100	56011	1.3340
2310010100	56013	1.3340
2310010100	56017	1.3340
2310010100	56019	0.9771
2310010100	56021	1.3340
2310010100	56023	1.3285
2310010100	56025	1.3340
2310010100	56027	1.3340
2310010100	56029	1.3340
2310010100	56033	0.9994
2310010100	56035	0.9955
2310010100	56037	1.3158
2310010100	56041	1.3340
2310010100	56043	1.3340
2310010100	56045	1.3340
2310010200	00000	1.2753
2310010200	08001	1.3340
2310010200	08005	1.3340
2310010200	08007	1.0022
2310010200	08009	1.3340
2310010200	08013	1.3340
2310010200	08017	1.3340
2310010200	08033	1.3340
2310010200	08039	1.3340
2310010200	08043	1.3340
2310010200	08045	1.3300
2310010200	08057	1.3340
2310010200	08061	1.3340
2310010200	08063	1.3340
2310010200	08067	1.3307
2310010200	08069	1.3340
2310010200	08073	1.3340
2310010200	08075	1.3340
2310010200	08077	1.3340
2310010200	08081	1.3253
2310010200	08083	1.3340
2310010200	08087	1.3340
2310010200	08099	1.3340
2310010200	08103	0.9979
2310010200	08107	1.3340
2310010200	08113	1.3340
2310010200	08115	1.3340
2310010200	08121	1.3340
2310010200	08123	1.3340
2310010200	30003	0.9649
2310010200	30005	0.9899
2310010200	30009	0.9746
2310010200	30019	1.3340
2310010200	30021	1.3340
2310010200	30025	1.3340
2310010200	30033	1.3340
2310010200	30035	1.3340
2310010200	30041	1.3340
2310010200	30051	1.3340
2310010200	30055	1.3340
2310010200	30065	0.9227
2310010200	30069	1.3340
2310010200	30073	1.3340

SCC	FIPS	Growth Factor
2310010200	30075	1.0000
2310010200	30079	1.3340
2310010200	30083	1.3340
2310010200	30085	1.3340
2310010200	30087	1.3340
2310010200	30091	1.3340
2310010200	30095	0.8333
2310010200	30099	1.3340
2310010200	30101	1.3340
2310010200	30105	1.3340
2310010200	30109	1.3340
2310010200	30111	1.0000
2310010200	32011	1.3340
2310010200	32023	1.3340
2310010200	35005	0.8660
2310010200	35015	0.8660
2310010200	35025	0.8660
2310010200	35031	0.9953
2310010200	35039	1.2786
2310010200	35041	0.8660
2310010200	35043	1.0263
2310010200	35045	1.7402
2310010200	38007	1.0336
2310010200	38009	1.3340
2310010200	38011	1.3340
2310010200	38013	1.3340
2310010200	38023	1.3340
2310010200	38025	1.3268
2310010200	38033	1.1452
2310010200	38041	1.3340
2310010200	38049	1.3340
2310010200	38053	1.1667
2310010200	38055	1.3340
2310010200	38061	1.3340
2310010200	38075	1.3340
2310010200	38087	0.9789
2310010200	38089	1.3340
2310010200	38101	1.3340
2310010200	38105	1.3340
2310010200	46041	1.3340
2310010200	46047	1.3340
2310010200	46063	1.3340
2310010200	49013	1.6365
2310010200	49015	1.3340
2310010200	49017	1.3340

SCC	FIPS	Growth Factor
2310010200	49019	1.3340
2310010200	49037	1.3340
2310010200	49043	1.3340
2310010200	49047	3.8530
2310010200	56001	1.3340
2310010200	56003	1.3340
2310010200	56005	0.9965
2310010200	56007	1.2974
2310010200	56009	1.0727
2310010200	56011	1.3340
2310010200	56013	1.3340
2310010200	56017	1.3340
2310010200	56019	0.9771
2310010200	56021	1.3340
2310010200	56023	1.3285
2310010200	56025	1.3340
2310010200	56027	1.3340
2310010200	56029	1.3340
2310010200	56033	0.9994
2310010200	56035	0.9955
2310010200	56037	1.3158
2310010200	56041	1.3340
2310010200	56043	1.3340
2310010200	56045	1.3340
2310010300	00000	1.2753
2310010300	08001	1.3340
2310010300	08005	1.3340
2310010300	08007	1.0022
2310010300	08009	1.3340
2310010300	08013	1.3340
2310010300	08017	1.3340
2310010300	08033	1.3340
2310010300	08039	1.3340
2310010300	08043	1.3340
2310010300	08045	1.3300
2310010300	08057	1.3340
2310010300	08061	1.3340
2310010300	08063	1.3340
2310010300	08067	1.3307
2310010300	08069	1.3340
2310010300	08073	1.3340
2310010300	08075	1.3340
2310010300	08077	1.3340
2310010300	08081	1.3253
2310010300	08083	1.3340

SCC	FIPS	Growth Factor
2310010300	08087	1.3340
2310010300	08099	1.3340
2310010300	08103	0.9979
2310010300	08107	1.3340
2310010300	08113	1.3340
2310010300	08115	1.3340
2310010300	08121	1.3340
2310010300	08123	1.3340
2310010300	30003	0.9649
2310010300	30005	0.9899
2310010300	30009	0.9746
2310010300	30019	1.3340
2310010300	30021	1.3340
2310010300	30025	1.3340
2310010300	30033	1.3340
2310010300	30035	1.3340
2310010300	30041	1.3340
2310010300	30051	1.3340
2310010300	30055	1.3340
2310010300	30065	0.9227
2310010300	30069	1.3340
2310010300	30073	1.3340
2310010300	30075	1.0000
2310010300	30079	1.3340
2310010300	30083	1.3340
2310010300	30085	1.3340
2310010300	30087	1.3340
2310010300	30091	1.3340
2310010300	30095	0.8333
2310010300	30099	1.3340
2310010300	30101	1.3340
2310010300	30105	1.3340
2310010300	30109	1.3340
2310010300	30111	1.0000
2310010300	32011	1.3340
2310010300	32023	1.3340
2310010300	35005	0.8660
2310010300	35015	0.8660
2310010300	35025	0.8660
2310010300	35031	0.9953
2310010300	35039	1.2786
2310010300	35041	0.8660
2310010300	35043	1.0263
2310010300	35045	1.7402
2310010300	38007	1.0336

SCC	FIPS	Growth Factor
2310010300	38009	1.3340
2310010300	38011	1.3340
2310010300	38013	1.3340
2310010300	38023	1.3340
2310010300	38025	1.3268
2310010300	38033	1.1452
2310010300	38041	1.3340
2310010300	38049	1.3340
2310010300	38053	1.1667
2310010300	38055	1.3340
2310010300	38061	1.3340
2310010300	38075	1.3340
2310010300	38087	0.9789
2310010300	38089	1.3340
2310010300	38101	1.3340
2310010300	38105	1.3340
2310010300	46041	1.3340
2310010300	46047	1.3340
2310010300	46063	1.3340
2310010300	49013	1.6365
2310010300	49015	1.3340
2310010300	49017	1.3340
2310010300	49019	1.3340
2310010300	49037	1.3340
2310010300	49043	1.3340
2310010300	49047	3.8530
2310010300	56001	1.3340
2310010300	56003	1.3340
2310010300	56005	0.9965
2310010300	56007	1.2974
2310010300	56009	1.0727
2310010300	56011	1.3340
2310010300	56013	1.3340
2310010300	56017	1.3340
2310010300	56019	0.9771
2310010300	56021	1.3340
2310010300	56023	1.3285
2310010300	56025	1.3340
2310010300	56027	1.3340
2310010300	56029	1.3340
2310010300	56033	0.9994
2310010300	56035	0.9955
2310010300	56037	1.3158
2310010300	56041	1.3340
2310010300	56043	1.3340

SCC	FIPS	Growth Factor
2310010300	56045	1.3340
2310020600	00000	2.1729
2310020600	30003	
2310020600	30005	1.2437
2310020600	30009	2.8663
2310020600	30015	1.4580
2310020600	30017	12.9403
2310020600	30019	1.4580
2310020600	30021	1.4580
2310020600	30025	1.4580
2310020600	30027	1.4580
2310020600	30033	1.4580
2310020600	30035	1.4580
2310020600	30037	1.9294
2310020600	30041	1.4580
2310020600	30051	1.4580
2310020600	30065	0.9227
2310020600	30069	1.4580
2310020600	30071	1.4580
2310020600	30073	1.4580
2310020600	30075	311.8023
2310020600	30079	1.4580
2310020600	30083	1.4580
2310020600	30085	1.4580
2310020600	30087	1.4580
2310020600	30091	1.4580
2310020600	30095	1.8116
2310020600	30097	1.7071
2310020600	30099	1.4580
2310020600	30101	1.4580
2310020600	30105	1.4580
2310020600	30109	1.4580
2310020600	32003	1.4580
2310020600	32023	1.4580
2310020600	35001	1.4580
2310020600	35005	1.3540
2310020600	35007	1.3540
2310020600	35015	1.3540
2310020600	35021	1.3540
2310020600	35025	1.3540
2310020600	35031	36.4321
2310020600	35039	2.9281
2310020600	35041	1.3540
2310020600	35043	1.2953
2310020600	35045	3.6832

SCC	FIPS	Growth Factor
2310020600	35059	1.3540
2310020600	38003	1.4580
2310020600	38007	1.0525
2310020600	38009	1.4580
2310020600	38011	1.4580
2310020600	38013	1.4580
2310020600	38015	1.4580
2310020600	38023	1.4580
2310020600	38025	1.4483
2310020600	38033	1.2043
2310020600	38049	1.4580
2310020600	38053	3.1848
2310020600	38055	1.4580
2310020600	38059	1.4580
2310020600	38061	1.4580
2310020600	38075	1.4580
2310020600	38077	1.4580
2310020600	38087	0.9789
2310020600	38089	1.4580
2310020600	38093	1.4580
2310020600	38101	1.4580
2310020600	38105	1.4580
2310020600	41009	0.5680
2310020600	41019	0.5680
2310020600	41041	0.5680
2310020600	41043	0.5680
2310020600	41047	0.5680
2310020600	46033	1.4580
2310020600	46041	1.4580
2310020600	46047	1.4580
2310020600	46063	1.4580
2310020600	49007	1.4580
2310020600	49009	2.1185
2310020600	49013	3.7360
2310020600	49015	1.4580
2310020600	49017	1.4580
2310020600	49019	1.4580
2310020600	49037	1.4580
2310020600	49043	1.4580
2310020600	49047	2.6255
2310020600	56001	1.4580
2310020600	56003	1.4580
2310020600	56005	7.1804
2310020600	56007	1.6387
2310020600	56009	1.1066

SCC	FIPS	Growth Factor
2310020600	56011	1.4580
2310020600	56013	1.4580
2310020600	56017	1.4580
2310020600	56019	6.9460
2310020600	56021	1.4580
2310020600	56023	1.5406
2310020600	56025	1.4580
2310020600	56027	1.4580
2310020600	56029	1.4580
2310020600	56033	7.6748
2310020600	56035	7.4527
2310020600	56037	1.5236
2310020600	56041	1.4580
2310020600	56043	1.4580
2310020600	56045	1.4580
2310021100	00000	2.3099
2310021100	08001	1.4580
2310021100	08005	1.4580
2310021100	08007	1.0177
2310021100	08009	1.4580
2310021100	08011	1.4580
2310021100	08013	1.4580
2310021100	08014	1.4580
2310021100	08017	1.4580
2310021100	08029	1.4580
2310021100	08031	1.4580
2310021100	08033	1.4580
2310021100	08039	1.4580
2310021100	08045	1.4595
2310021100	08051	1.4580
2310021100	08055	1.4580
2310021100	08057	1.4580
2310021100	08061	1.4580
2310021100	08063	1.4580
2310021100	08067	1.4535
2310021100	08069	1.4580
2310021100	08071	1.4580
2310021100	08073	1.4580
2310021100	08075	1.4580
2310021100	08077	1.4580
2310021100	08081	1.4638
2310021100	08083	1.4580
2310021100	08087	1.4580
2310021100	08095	1.4580
2310021100	08099	1.4580

SCC	FIPS	Growth Factor
2310021100	08103	1.6764
2310021100	08107	1.4580
2310021100	08113	1.4580
2310021100	08121	1.4580
2310021100	08123	1.4580
2310021100	08125	1.4580
2310021100	30005	1.2437
2310021100	30009	3.6853
2310021100	30015	1.4580
2310021100	30017	12.9403
2310021100	30025	1.4580
2310021100	30027	1.4580
2310021100	30035	1.4580
2310021100	30037	1.9294
2310021100	30041	1.4580
2310021100	30051	1.4580
2310021100	30071	1.4580
2310021100	30073	1.4580
2310021100	30075	371.1493
2310021100	30079	1.4580
2310021100	30083	1.4580
2310021100	30085	1.4580
2310021100	30091	1.4580
2310021100	30095	1.8116
2310021100	30097	1.7071
2310021100	30099	1.4580
2310021100	30101	1.4580
2310021100	30105	1.4580
2310021100	30109	1.4580
2310021100	32023	1.4580
2310021100	35001	1.4580
2310021100	35005	1.3540
2310021100	35007	1.3540
2310021100	35015	1.3540
2310021100	35021	1.3540
2310021100	35025	1.3540
2310021100	35031	36.4321
2310021100	35039	2.9921
2310021100	35041	1.3540
2310021100	35043	1.4274
2310021100	35045	3.7217
2310021100	35059	1.3540
2310021100	38011	1.4580
2310021100	38013	1.4580
2310021100	38053	5.9557

SCC	FIPS	Growth Factor
2310021100	38105	1.4580
2310021100	41009	0.5680
2310021100	46063	1.4580
2310021100	49007	1.4580
2310021100	49009	2.1185
2310021100	49013	116.0424
2310021100	49015	1.4580
2310021100	49019	1.4580
2310021100	49037	1.4580
2310021100	49043	1.4580
2310021100	49047	2.5806
2310021100	56001	1.4580
2310021100	56003	1.4580
2310021100	56005	0.9965
2310021100	56007	1.6616
2310021100	56009	1.1075
2310021100	56011	1.4580
2310021100	56013	1.4580
2310021100	56017	1.4580
2310021100	56019	0.9771
2310021100	56023	1.5411
2310021100	56025	1.4580
2310021100	56027	1.4580
2310021100	56029	1.4580
2310021100	56035	7.4972
2310021100	56037	1.5467
2310021100	56041	1.4580
2310021100	56043	1.4580
2310021100	56045	1.4580
2310021300	00000	2.3099
2310021300	08001	1.4580
2310021300	08005	1.4580
2310021300	08007	1.0177
2310021300	08009	1.4580
2310021300	08011	1.4580
2310021300	08013	1.4580
2310021300	08014	1.4580
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2310021300	08029	1.4580
2310021300	08031	1.4580
2310021300	08033	1.4580
2310021300	08039	1.4580
2310021300	08045	1.4595
2310021300	08051	1.4580
2310021300	08055	1.4580

SCC	FIPS	Growth Factor
2310021300	08057	1.4580
2310021300	08061	1.4580
2310021300	08063	1.4580
2310021300	08067	1.4535
2310021300	08069	1.4580
2310021300	08071	1.4580
2310021300	08073	1.4580
2310021300	08075	1.4580
2310021300	08077	1.4580
2310021300	08081	1.4638
2310021300	08083	1.4580
2310021300	08087	1.4580
2310021300	08095	1.4580
2310021300	08099	1.4580
2310021300	08103	1.6764
2310021300	08107	1.4580
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2310021300	08121	1.4580
2310021300	08123	1.4580
2310021300	08125	1.4580
2310021300	30005	1.2437
2310021300	30009	3.6853
2310021300	30015	1.4580
2310021300	30017	12.9403
2310021300	30025	1.4580
2310021300	30027	1.4580
2310021300	30035	1.4580
2310021300	30037	1.9294
2310021300	30041	1.4580
2310021300	30051	1.4580
2310021300	30071	1.4580
2310021300	30073	1.4580
2310021300	30075	371.1493
2310021300	30079	1.4580
2310021300	30083	1.4580
2310021300	30085	1.4580
2310021300	30091	1.4580
2310021300	30095	1.8116
2310021300	30097	1.7071
2310021300	30099	1.4580
2310021300	30101	1.4580
2310021300	30105	1.4580
2310021300	30109	1.4580
2310021300	32023	1.4580
2310021300	35001	1.4580
2310021300	35005	1.3540
2310021300	35007	1.3540
2310021300	35015	1.3540
2310021300	35021	1.3540
2310021300	35025	1.3540
2310021300	35031	36.4321
2310021300	35039	2.9921
2310021300	35041	1.3540
2310021300	35043	1.4274
2310021300	35045	3.7217
2310021300	35059	1.3540
2310021300	38011	1.4580
2310021300	38013	1.4580
2310021300	38053	5.9557
2310021300	38105	1.4580
2310021300	41009	0.5680
2310021300	46063	1.4580
2310021300	49007	1.4580
2310021300	49009	2.1185
2310021300	49013	116.0424
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2310021300	49047	2.5806
2310021300	56001	1.4580
2310021300	56003	1.4580
2310021300	56005	0.9965
2310021300	56007	1.6616
2310021300	56009	1.1075
2310021300	56011	1.4580
2310021300	56013	1.4580
2310021300	56017	1.4580
2310021300	56019	0.9771
2310021300	56023	1.5411
2310021300	56025	1.4580
2310021300	56027	1.4580
2310021300	56029	1.4580
2310021300	56035	7.4972
2310021300	56037	1.5467
2310021300	56041	1.4580
2310021300	56043	1.4580
2310021300	56045	1.4580
2310021400	00000	2.3099
2310021400	32023	1.4580
2310021400	35001	1.4580
2310021400	35005	1.3540
2310021400	35007	1.3540
2310021400	35015	1.3540
2310021400	35021	1.3540
2310021400	35025	1.3540
2310021400	35031	36.4321
2310021400	35039	2.9921
2310021400	35041	1.3540
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2310021400	35045	3.7217
2310021400	35059	1.3540
2310021400	38011	1.4580
2310021400	38013	1.4580
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2310021400	38105	1.4580
2310021400	41009	0.5680
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2310021400	49007	1.4580
2310021400	49009	2.1185
2310021400	49013	116.0424
2310021400	49015	1.4580
2310021400	49019	1.4580
2310021400	49037	1.4580
2310021400	49043	1.4580
2310021400	49047	2.5806
2310021400	56001	1.4580
2310021400	56003	1.4580
2310021400	56005	0.9965
2310021400	56007	1.6616
2310021400	56009	1.1075
2310021400	56011	1.4580
2310021400	56013	1.4580
2310021400	56017	1.4580
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2310021400	56029	1.4580
2310021400	56035	7.4972
2310021400	56037	1.5467
2310021400	56041	1.4580
2310021400	56043	1.4580
2310021400	56045	1.4580
2310021500	00000	2.3099

SCC	FIPS	Growth Factor
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2310021500	08001	1.4580
2310021500	08009	1.4580
2310021500	08013	1.4580
2310021500	08014	1.4580
2310021500	08017	1.4580
2310021500	08045	1.4595
2310021500	08067	1.4535
2310021500	08071	1.4580
2310021500	08073	1.4580
2310021500	08075	1.4580
2310021500	08077	1.4580
2310021500	08081	1.4638
2310021500	08087	1.4580
2310021500	08099	1.4580
2310021500	08103	1.6764
2310021500	08113	1.4580
2310021500	08121	1.4580
2310021500	08123	1.4580
2310021500	08125	1.4580
2310021500	30005	1.2437
2310021500	30015	1.4580
2310021500	30025	1.4580
2310021500	30041	1.4580
2310021500	30051	1.4580
2310021500	30071	1.4580
2310021500	30101	1.4580
2310021500	30105	1.4580
2310021500	35001	1.4580
2310021500	35005	1.3540
2310021500	35007	1.3540
2310021500	35015	1.3540
2310021500	35025	1.3540
2310021500	35039	2.9921
2310021500	35045	3.7217
2310021500	35059	1.3540
2310021500	38011	1.4580
2310021500	49007	1.4580
2310021500	49043	1.4580
2310021500	49047	2.5806
2310021500	56003	1.4580
2310021500	56005	0.9965
2310021500	56007	1.6616
2310021500	56013	1.4580
2310021500	56023	1.5411

SCC	FIPS	Growth Factor
2310021500	56025	1.4580
2310021500	56029	1.4580
2310021500	56035	7.4972
2310021500	56037	1.5467
2310021500	56041	1.4580
2310023000	00000	1.6924
2310023000	08007	1.4580
2310023000	08045	1.4580
2310023000	08055	1.4580
2310023000	08067	1.5838
2310023000	08071	1.4580
2310023000	08077	1.4580
2310023000	08081	1.4580
2310023000	08103	0.9955
2310023000	08107	1.4580
2310023000	35007	0.0000
2310023000	35039	1.9105
2310023000	35045	1.9162
2310023000	56005	7.6917
2310023000	56007	1.4580
2310023000	56009	7.6666
2310023000	56019	7.6901
2310023000	56033	7.6748
2310023000	56035	0.9926
2310023000	56037	1.4580
2310023000	56041	1.4580
2310030210	00000	2.3099
2310030210	35001	1.4580
2310030210	35005	1.3540
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2310030210	35025	1.3540
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2310030210	35041	1.3540
2310030210	35043	1.4274
2310030210	35045	3.7217
2310030210	49007	1.4580
2310030210	49009	2.1185
2310030210	49013	116.0424
2310030210	49015	1.4580
2310030210	49019	1.4580
2310030210	49037	1.4580
2310030210	49043	1.4580
2310030210	49047	2.5806
2310030210	56003	1.4580
2310030210	56005	0.9965

SCC	FIPS	Growth Factor
2310030210	56007	1.6616
2310030210	56009	1.1075
2310030210	56013	1.4580
2310030210	56017	1.4580
2310030210	56023	1.5411
2310030210	56025	1.4580
2310030210	56027	1.4580
2310030210	56029	1.4580
2310030210	56035	7.4972
2310030210	56037	1.5467
2310030210	56041	1.4580
2310030210	56043	1.4580
2310030210	56045	1.4580
2310030220	30009	3.6853
2310030220	30035	1.4580
2310030220	30091	1.4580
2310030220	30101	1.4580
2310030220	38013	1.4580
2310030220	38053	5.9557
2310030220	38105	1.4580
2310030220	56005	0.9965
2310030220	56007	1.6616
2310030220	56009	1.1075
2310030220	56013	1.4580
2310030220	56023	1.5411
2310030220	56025	1.4580
2310030220	56027	1.4580
2310030220	56029	1.4580
2310030220	56035	7.4972
2310030220	56037	1.5467
2310030220	56041	1.4580
2310030220	56043	1.4580
2310030220	56045	1.4580

EXHIBIT 4

Bar-Ilan, A., R. Friesen, A. Pollack, and A. Hoats, "WRAP Area Source Emissions Inventory Projections and Control Strategy Evaluation, Phase II," Final Report Prepared for Western Governor's Association (September 2007)

ENVIRON

International Corporation

Air Sciences

Final Report

WRAP AREA SOURCE EMISSIONS INVENTORY PROECTIONS AND CONTROL STRATEGY EVALUATION PHASE II

Prepared for

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September 2007

PREFACE

Regulatory Framework for Tribal Visibility Implementation Plans

The Regional Haze Rule explicitly recognizes the authority of tribes to implement the provisions of the Rule, in accordance with principles of Federal Indian law, and as provided by the Clean Air Act (CAA) §301(d) and the Tribal Authority Rule (TAR) (40 CFR §§49.1– .11). Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.

2. Federally recognized tribes may apply for and receive delegation of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a Tribal Implementation Plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.

3. The Regional Haze Rule expressly provides that tribal visibility programs are "not dependent on the strategies selected by the state or states in which the tribe is located" (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12).

4. The EPA has indicated that under the TAR tribes are not required to submit §309 TIPs by the end of 2003; rather they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).

5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a Federal Implementation Plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a government to government basis in developing tribe-specific or generally applicable TIPs where necessary (See, e.g., 63 Fed. Reg.7263-64).

The amount of modification necessary will vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

Tribal Participation in the WRAP

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board.

Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred federally recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members Forum and Committee members and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by states and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, the tribal participants have joined the state, federal, and private stakeholder interests in approving this report as a consensus document.

An adjunct study of oil and gas emissions point and area source emissions was conducted by ENVIRON and ERG. Oil and gas emissions for four tribes were inventoried: Wind River Reservation, Ute Mountain Ute Tribe, Navajo Nation, and Jicarilla Apache Nation. Emissions sources for the Jicarilla Apache Nation were inventoried, but they elected to not formally participate in the project. The final project report, *Point Source and Oil and Gas Area Source Emission Inventories on Native American Reservations and Tribal Lands* (ERG/ENVIRON, 2005), does not include Jicarilla Apache data.

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1. INTRODUCTION

Background

In 2002, more than 5.6 trillion cubic feet of natural gas and 1.15 billion barrels of crude oil were drawn from oil and gas wells in the 14 western states (EIA, 2006a, EIA, 2006b). In 2005, those numbers were 6.4 trillion cubic feet of natural gas and 1.1 billion barrels of crude oil (US DOE, 2007). To achieve this level of production, an extensive fleet of oil and gas production equipment operates continuously across the Western U.S. The sizes and types of equipment in that fleet vary from small chemical injection pumps up to gas turbines of several thousand horsepower. Despite their differences, at least one common feature unites many of these equipment types. They emit nitrous oxides (NOx), volatile organic compounds (VOC) and other air pollutants as part of their normal daily operations. Even the smallest of these source types generate significant emissions when the continuous operation and the number of units are taken into consideration. Previous emission inventories have addressed limited segments of the oil and gas production industry. In particular, large oil and gas facilities have been well accounted for in state point source inventories. Thus this inventory represents an effort to create a more systematic, region-wide emissions inventory for oil and gas area sources in the western states of the U.S.

This inventory represents the second phase of a region-wide inventory of oil and gas area sources in the Western U.S. Prior to the first phase of this work, the only significant emissions inventory efforts to address oil and gas area source emissions were a statewide inventory in Wyoming (Pollack, A.K.; Russell, J.; Rao, S.; Mansell, G., 2005), a statewide oil and gas emissions inventory in California that identified some minor wellhead processes (CARB, 2007a), and some focused studies by the New Mexico Oil and Gas Association (NMOGA) in northwestern New Mexico (NMOGA, 2003). Thus the WRAP Phase I emissions inventory represented the first time that a region-wide estimate was made of oil and gas area sources (Russell, J.; Pollack, A., 2006). That inventory focused on drilling rigs, compressors, coal bed methane pump engines, and minor NOx sources such as heaters, tanks, glycol dehydrator units and pneumatic devices. Due to the limited availability of regional-specific data, the Phase I emissions inventory was regionally uniform in terms of activity source type (e.g., compressor engine size distribution) and so associated emission estimates were more uniform by the number and types of engines.

Following the original Phase I emissions inventory, the New Mexico Environment Department (NMED) funded a detailed study of oil and gas area sources in northwestern New Mexico to establish a revised emissions inventory for oil and gas area sources in San Juan and Rio Arriba counties (Pollack, A.; Russell, J.; Grant, J.; Friesen, R.; Fields, P.; Wolf, M. 2006.). For this emissions inventory effort, a survey questionnaire was developed to obtain detailed information on oil and gas operations directly from the major producers in these counties. The companies responding to this survey collectively owned and operated about 60 percent of the wells in these two counties. Because significant resources were available to conduct a detailed equipment-specific inventory for these two counties, this approach was much more accurate than the emissions for these two counties in the WRAP Phase I project.

Based on these previous emissions inventory efforts, WRAP contracted with ENVIRON to provide an updated Phase II WRAP region-wide emissions inventory of oil and gas area sources to be used in regional haze modeling for states' regional haze SIP compliance. ENVIRON was tasked only to estimate oil and gas *area* sources, while point source emissions were developed through a separate inventory effort.

Objectives and Approach

The methodologies and results presented in this report are the result of a second phase of emissions inventory analysis that builds upon the Phase I work conducted in 2005-2006. The goal of the project was to improve upon the original WRAP area-wide inventory, by updating the methodology used to generate the emissions inventory, updating information on control strategies, and updating the 2018 emissions projections including the impact of the control strategies on these emissions. The specific tasks addressed in this new inventory analysis were:

1) Improvements to the 2002 Emissions Inventory - This task focused on improving estimates of the emissions inventory of NOx, SOx and PM from O&G operations. These criteria pollutants can have serious potential health consequences, are smog-forming precursors, and can negatively impair visibility. The most significant emissions of NOx in the WRAP regions are from drill rigs and from natural gas-fired compressor engines. The most important sources of SOx and PM emissions are from drilling rig engines, and from minor H2S emissions in some O & G operations in southwest New Mexico. Some effort was made to distinguish between emissions from conventional gas wells and coal bed methane (CBM) gas wells as these are expected to have some differences. Work focused on drilling rigs, gas compressor engines, CBM operations.

2) Updating Baseline Emissions from 2002 to 2005 – Calendar year 2005 wells and production data were available from state Oil and Gas Commissions (OGCs), and were used to estimate O&G area source emissions in 2005. This estimate provides a more current year of emissions inventory results, with emissions matched to more current activity levels, and served as the basis from which to project the 2018 emissions. The approach used to generate 2005 emissions was to first revise the 2002 emissions using methods discussed below for specific source categories, to generate county-level emissions using this methodology, and then to scale up the revised 2002 county-level emissions to 2005 using county-level 2005/2002 OGC production and/or well count data. The choice of production or well count data for scaling was made for each process separately, based on which type of data was the basis for the revised 2002 emissions calculations

3) Control Strategy Evaluation – Potential control strategies for drilling rigs and compressors were identified and a series of white papers developed that provide a detailed description of these control technologies. The white papers contain an analysis of the emissions reduction potential, the cost and cost-effectiveness of NOx reductions from control measures aimed at compressor engines and drilling rigs, and to a limited extent from VOC sources involved in exploration and production of natural gas. Control strategies identified include engine modifications, emissions control retrofit technology, and modernization of equipment through repowering or replacing engines. The application of a mix of control measures to the San Juan Basin in New Mexico, with

assumed penetration rates for each measure for drilling rigs and compressors, is presented as an example of the methodology for investigating the emissions reduction potentials and cost of a controls scenario.

4) 2018 Emissions Forecasts - The Phase I 2018 oil and gas emissions estimates were developed by projecting 2002 emissions based on a combination of production data and well count data. The objective of this task was to review these sources of data, utilize new sources of data if available, and then conduct projections of the 2005 county-level emissions to 2018. The projections were developed from regional production forecasts in the Annual Energy Outlook (AEO) generated by the Energy Information Administration (EIA)3, from local Resource Management Plans (RMPs) in specific geographic areas, from Environmental Impact Reports/Statements (EIR/S) for specific areas, and any other available local and regional planning documents. The objective was to use these data sources to project uncontrolled 2018 emissions, except for the incorporation of "on-the-books" controls that have already been enacted by some states.

5) Improvements to Point Source SOx Emissions in 2018 - The objective of this task was to revise the emissions of SOx from large point sources due to oil and gas operations in the WRAP region in 2018. These point sources are primarily natural gas processing plants located in Wyoming and New Mexico. Previous projections of these plants' SOx emissions have not included recent advances in SOx removal technology that oil and gas producers have been increasingly utilizing to reduce SOx emissions from these sources. The approach used was to revise the control assumptions, and more importantly to develop the projection factors based on the 2018 production projections that were developed as part of task 3 above.

The discussion of these five tasks in this report is organized chronologically: it begins with the 2002 emissions inventory update for select source categories; next the 2002-to-2005 scale up of emissions is presented; the evaluation of control technologies is presented in the white papers for each control measure considered; the projections from 2005 emissions to 2018 emissions are discussed; and finally the methodology and revised 2018 SOx point source emissions are discussed. Each section describes the detailed methodology used and present the quantitative results. The final section describes the resulting western U.S. oil and gas area source emissions inventory for all of the states considered here.

The resulting inventory differs significantly from the Phase I inventory. The major differences between the Phase I and Phase II inventories are the improved activity and equipment information in the Phase II inventory, for both drilling rigs and compressors. More detailed information was provided by producers on emissions factors for specific equipment types, however because the project resources were limited not all pollutants were addressed. All updated information from the producers was provided on a geographically specific basis, thus those geographic areas which were updated in this Phase II inventory have more accurate emissions predictions than those areas which remained unchanged from the Phase I inventory.

Limitations of this Inventory

Although this Phase II inventory represents an improvement over the Phase I inventory, there are some limitations to the scope of this inventory:

- Not all pollutants from oil and gas area source categories were evaluated. For the drilling rigs and compressors which were the focus of this inventory, not all pollutant emissions from these two equipment types were considered. PM, HC and CO emissions factor information for all engines were not available for every engine identified, and given the wide range of engine sizes and ages considered it was determined that insufficient information was available to estimate PM, HC and CO emissions from some of these engines. Emissions of NOx were considered the focus of this inventory.
- Detailed lists of equipment could not be identified for all focus geographic regions. In some areas, only a small number of equipment types were identified from producer data and broad assumptions needed to be made about this equipment.
- In some geographic regions activity data was more detailed than others. Information about the frequency of maintenance activities, or emergency or mechanical down-time for equipment was not always available. A greater response from producers may resolve this issue in any possible future inventory.
- Some geographic areas were not considered. Although the aim of the Phase II inventory was to identify and assess all geographic areas of major oil and gas activity, some areas were not considered. Due to the limited resources available for surveying producers, the oil and gas producing basins in Montana and North Dakota were not part of the focused regions that were considered, and the Phase I emissions estimates for these areas were carried through. Information about oil and gas activity in Alaska was not easily available and it would entail significant resources and effort to estimate activity there, so Phase I estimates were carried forward.
- Not all major sources of NOx were updated in the Phase II work. As noted above, compressor and drilling rig NOx emissions were the focus of the Phase II project. Heaters used to provide heat for separators or tanks were not updated and the Phase I estimates for heater emissions were carried forward. Other minor NOx sources such as flares and completions were not inventoried in the Phase II work.
- VOC emissions are incomplete and were not specifically updated in this Phase II work. VOCs were estimated in the Phase I work from tanks, glychol dehydrators, pneumatic devices and flaring and venting, however these estimates could be greatly improved. In the NMED inventory for San Juan and Rio Arriba counties, the VOC emissions for oil and gas area sources were 52,000 tons per year greater than the Phase I inventory for these same two counties, which represented a 98 percent increase in VOC emissions. The Phase I work also did not consider some VOC source categories such as flaring and breathing losses.
- Hazardous air pollutants were not considered. Hazardous air pollutants (HAPs) were not considered in this inventory for any source category.
- PM emissions from combustion and fugitive dust were not considered. PM emissions factors from direct combustion were difficult to find for all engine types, and activity and other information needed to estimate fugitive dust emissions were not available.
- Greenhouse gas emissions were not estimated. Emissions of CO2 and methane were not estimated for this Phase II inventory.

Further details on what is and is not included in this Phase II oil and gas area source emissions inventory are provided in the report.

Political Jurisdictions

In the Phase II inventory effort, emissions were estimated on a county basis (using basin-specific information), and summed to obtain state-wide emissions. The emissions in this report are presented on a state-wide basis. Basins are often located in more than one state. Some counties lie within more than one basin, and in such cases the county emissions were divided among the appropriate basins on the basis of the available information – either well count in the county or gas and oil production in the county. In all cases, the equipment and activity of that equipment were considered uniform within a basin. No effort was made to track the movement of equipment from one basin to another.

The Phase I inventory separated out emissions from wells on tribal lands – this Phase II inventory did not separate out tribal emissions. These emissions are included in the state-wide oil and gas area source emissions totals.

Point vs. Area Sources

This Phase II inventory, similarly to the Phase I inventory, includes only oil and gas area sources. Point sources were not considered in this inventory, as they are analyzed and inventoried separately. In order to determine what would be included in a state's point source inventory, ENVIRON examined the state-by-state emissions thresholds that trigger reporting in a state's point source inventory. This differed from state to state; however for most states the assumption that wellhead compressors were not in the point source inventory was a reasonable one. The only two states for which this rule does not apply are Colorado and Alaska. In Colorado, the point source inventory reporting threshold is 2 tons per year of NOx. This state point source inventory was therefore assumed to include all compressors, including wellhead compressors. ENVIRON made no further effort to inventory these sources in Colorado, in an effort to avoid double-counting with Colorado's point source inventory. Compressor stations in Alaska operate in a hub-and-spoke system, in which the small wellhead compressors are associated with the large central compressor stations they serve. Therefore in Alaska all wellhead compressors emissions were included in the point source inventory of the major compressor stations. The report shows both area source and point source oil and gas emissions totals for each state in the WRAP region for 2002 in Section 2, and for 2018 in Section 5.

2. 2002 EMISSIONS INVENTORY IMPROVEMENTS

The focus of the 2002 emissions inventory improvements was on NOx and SOx emissions from oil and gas (O&G) area sources. The most significant emissions of NOx in the WRAP region are from drill rigs and from natural gas-fired compressor engines. The most important sources of SOx emissions are from drilling rig engines, and from minor H_2S content in natural gas that is combusted. There are additionally some minor SOx emissions from coal bed methane (CBM) wells' pump engines in New Mexico where H_2S is sometimes present.

Prior work in the WRAP region was limited by available information and accordingly, certain assumptions about O&G production were improved upon. The Phase I work made estimates of drilling time and activity on the basis of state Oil and Gas Commissions (OGCs) databases, which did not provide enough detail for an accurate calculation of actual drilling times. Drilling rig engine loads were assumed to be at the maximum capacity for that engine, and a similar assumption was made for compressors. Actual loads vary significantly with the type of O&G operation being considered and vary widely particularly for compressor engines. An inventory project for the New Mexico Environment Department (NMED) focused on improving these estimates and assumptions, but studied only O&G operations in San Juan and Rio Arriba counties in northwest New Mexico (Russell, J.; Pollack, A., 2006). Thus this work was limited to the types of operations in this geographic region. The analysis presented here focuses on expanding the types of revised estimates made in the NMED work to other WRAP producing regions, as well as incorporating more recent information from O&G producers in the WRAP region on their specific utilization of drilling rigs and gas compressors in their O&G operations. The revised estimates make use of information about the geography of the O&G operations and the producers' specific operations.

Field/Basin Information

Given the geographic size of the WRAP region, a new methodology was developed that both makes use of geographically-specific equipment and activity assumptions, and generalizes these assumptions in a tractable way. Activity, equipment and emissions were assumed to be uniform throughout a geologic basin, and estimates of emissions were then conducted separately for each basin in the WRAP region in which major O&G activity was occurring.

A structural basin is a large-scale structural formation of rock strata formed by tectonic warping of previously flat lying strata (Monroe, J.S.; Wicander, R.. 1997). Structural basins are synonymous in some ways with geological depressions (Monroe, J.S.; Wicander, R.. 1997). Within a basin are potentially many oil and gas producing fields where drilling is occurring and wells are sited. Grouping equipment and emissions by field would be intractable as there are literally thousands of active fields in the western United States – and thus the analysis was made by grouping activity, equipment and emissions by basin.

Another significant update in this analysis compared to the prior work is that information was obtained directly from the O&G producers to better identify the basins where major O&G operations were occurring and to obtain specific activity and equipment details of those operations. Based upon the information supplied by producers, the emission inventory efforts were focused on those areas where significant production is occurring and where a significant potential existed to improve the inventory. The basins in which significant O&G activities were occurring in 2002 and 2005 are:

- Wyoming: Southwestern Wyoming (Green River) Basin; Wind River Basin; Big Horn Basin; Powder River Basin
- Colorado: Denver-Julesburg Basin; Uinta-Piceance Basin; San Juan (North) Basin
- Utah: Uinta-Piceance Basin; Paradox Basin
- New Mexico: San Juan (South) Basin; Permian Basin

These basins include the Four Corners region, Southeast New Mexico, Utah, Colorado, Southwest Wyoming, North Central Wyoming, and Northeast Wyoming. Figure 2-1 shows the basins in the WRAP region and highlights the focused basins. The Big Horn and Powder River basins in Wyoming also cover active regions in Montana that lie within these basins. Idaho, Washington, Oregon, Nevada and Arizona were not a focus of this emission inventory analysis because O&G operations occurring in these areas are less significant. California was not included in this analysis because O&G operations have been traditionally inventoried and regulated through the California Air Resources Board (CARB). Alaska represents a special case. Most oil and gas production in Alaska occurs at large centralized stations that are considered point sources and have been included in point source inventories. Where wellhead equipment is used, it is typically arranged in a "hub-and-spoke" configuration that ensures that it is included in the permitted equipment of the large central gas processing station (the "hub"). Thus for Alaska the only major area source category that was considered was drilling rigs.

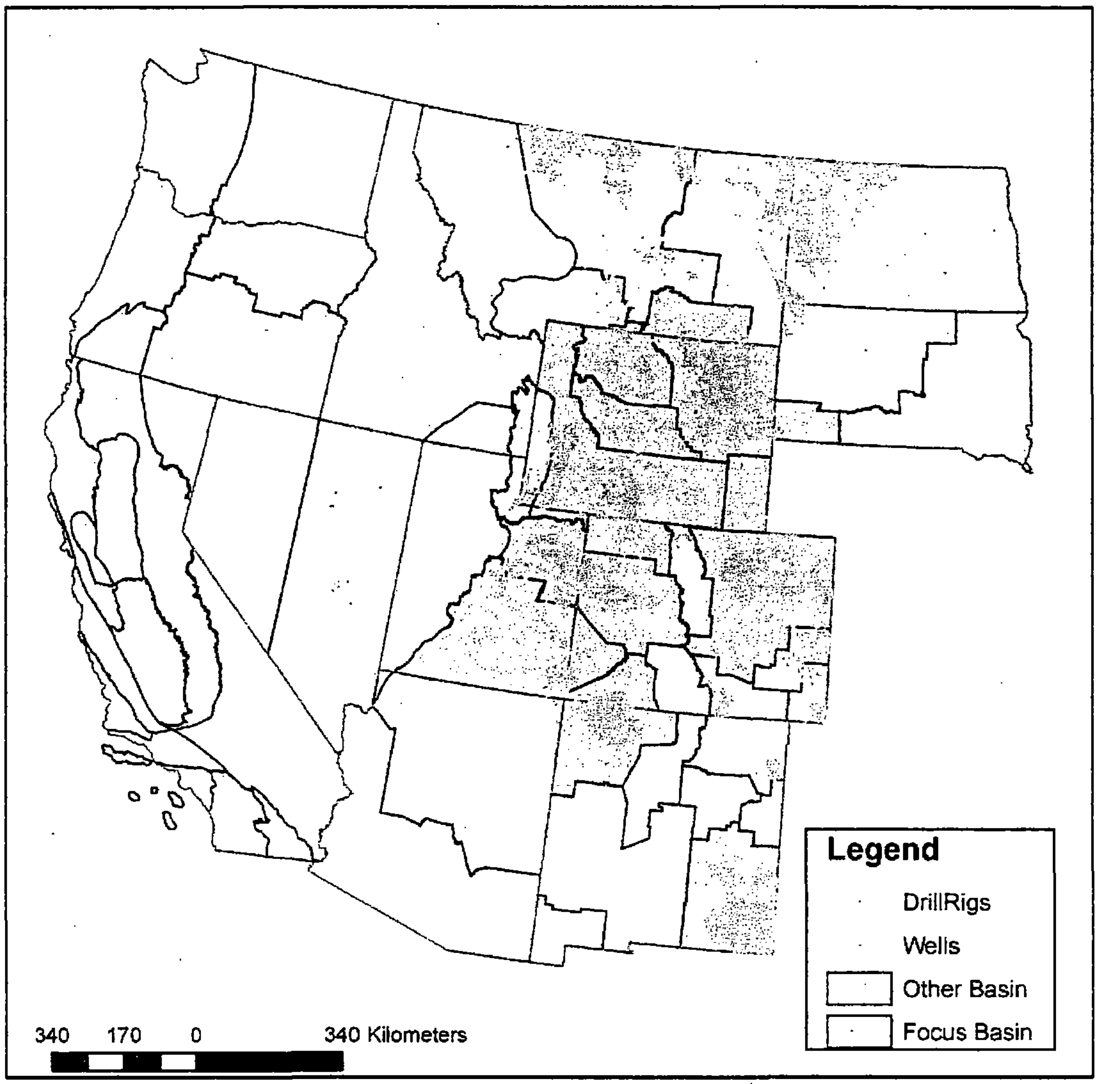


Figure 2-1. Oil and gas producing wells and drilling sites in the western regional U.S., and production basins and focus basins in the western regional U.S.

The methodology involved collecting producer information on specific basins where the producer has significant operations. Each producer provided detailed information for the basin where they operate, and these data were used to estimate overall average characterization of O&G operations and emissions in each basin. Where multiple producers were operating extensively in a single basin, each producer's detailed information was used to create a weighted average of activity based on each producer's well count in the basin as a fraction of the total well count.

The database of well-specific information from state OGC's that was developed in the Phase I analysis for 2002 was used to identify basin boundaries and the well counts within each basin. These basins were then intersected with county lines to determine the fraction of each county in the WRAP region that lies within a focus basin. It should be noted that where specific information on operations in a basin was not available, the emissions estimate from the Phase I analysis were used.

Drilling Rig Emissions

The WRAP Phase I approach developed to estimate emissions from drill rig engines used drill permit data from oil and gas commissions (OGCs) as a measure of activity and emission factors derived from a survey of drilling companies. The drill permit data were used to determine the drilling time and drilling depth, as well as a total count of wells drilled in 2002. The survey of drilling companies yielded results for representative equipment in only one region – the Jonah-Pinedale area of the Green River Basin in Wyoming. Given this lack of data, it was necessary to scale equipment emissions factors and horsepower from the Jonah-Pinedale study by well depth and drilling time to other fields, introducing potential inaccuracy to the emissions estimates. Another source of inaccuracy was the drilling times derived from the state OGC databases. These databases recorded the spud date – the date when drilling begins – and the completion date of the well when production begins. However, drilling occurs during only a fraction of that time, with the remainder of that time being reserved for well completion activities. This fraction varies widely by geographic location, and is generally a function of the type of rock in which the drilling occurs, and the depth of the drilling. The use of a single drilling time fraction in the previous analysis introduced inaccuracy to the emissions calculations. Furthermore, due to lack of information, the Phase I analysis assumed that all drilling rigs operate at 100% engine load.

Thus there were several aspects of the drilling rig emissions estimates that could potentially be improved in the Phase II analysis. The NMED work improved these estimates for northwest New Mexico by obtaining drilling stop times from operators in this region (rather than well completion times), by obtaining actual horsepower and emissions factors characteristics of each engine inventoried, and by derating the maximum power of the engine to account for well depth. Also, the NMED work made use of emissions testing conducted on three representative drilling rig engines manufactured by Detroit Diesel to derive representative emissions factors for drilling rigs.

The current analysis leveraged the additional information provided directly by producers. Producers were asked to provide details of the operational and equipment characteristics of drilling rigs as part of the survey of producers, which specifically asked:

1) What are the actual average drilling times (start drilling to stop drilling dates) for wells in the basin?
2) What is the average depth of wells drilled in the basin?
3) What is the actual average load factor of the drilling rig engines operating in the basin?
4) What is the average horsepower of drilling rig engines operating in the basin?
5) Please identify a representative make and model of drilling rig engine (or up to 3 representative makes and models) that are most frequently used in the basin.
6) What are the measured or manufacturer's rated emissions factors for the drilling rigs identified in (5) above?
7) What type of fuel is used in these drilling rigs, and can the exact sulfur content of that fuel be provided?
8) What is the fuel consumption of a representative make and model of drilling rig as it drills to an average well depth for an average duration?

This information allowed for an improved estimate of actual drilling stop times and drilling horsepower needs. Average drilling times, depths and horsepower were used to derive a representative basin average emissions per well drilled. This corrected for any potential errors in drilling time estimates made in the Phase I where the drilling times were extrapolated as a function of total well preparation time from only the Jonah-Pinedale region. The producers contacted as part of the current analysis have indicated that the Jonah-Pinedale area may not be representative of drilling needs and activities at other locations. Based on information obtained from producers and the NMED analysis, actual drill times and therefore drilling emissions may have been overestimated because drilling rigs are removed from operation once a desired well depth has been reached. Any remaining operations at the well are handled by well completion equipment. For the San Juan Basin in New Mexico, the detailed NMED analysis was used directly because it was deemed to be more accurate than the basin-average methodology described here (Pollack, A.; Russell, J.; Grant, J.; Friesen, R.; Fields, P.; Wolf, M. 2006).

Based on specific information obtained from producers, it was determined that the drilling horsepower requirements are based upon the anticipated drilling depth and drilling time, rather than by the formation type. The load factors used for drilling rig engines in previous estimates were improved upon based on specific information from producers. The information provided by producers indicated that the 100% load assumed in the Phase I work was incorrect and that in fact drilling rig engines are often operated at loads of approximately 50% due to the fact that the engine is overpowered for the drilling application. Where information was available from producers about drilling engine load factors, those factors were used. The producers also provided a representative engine configuration for up to three most commonly used drilling rigs in each basin. If more than one representative drilling rig configuration was cited, emissions were estimated for the representative well for each rig and averaged. This represented a substantial improvement over previous estimates because it was found that drilling rigs are often composed of multiple engines, each performing different tasks for different lengths of time and different engine loads, as well as having different emissions factors for each engine (Flanders, C., 2007). Some drill rigs are made up of as many as four engines: two draw-works engines that control the drill string, one mud pump engine that controls all pumping activity, and one generator engine to provide electrical power.

The general procedure for estimating drilling rig emissions was to develop a representative emissions estimate per well in a basin. The average depth of wells in a basin was obtained from producers, and a weighted average well depth was derived for each basin, where the weighting factors were the number of wells that each producer operated in that basin. The same procedure was used for the actual drilling times as reported by producers. This information was combined to derive an average emissions per well for a basin according to Equation 2-1.

Equation 2-1:

$$E_{basin,avg} = \sum_i LF_i \times HP_i \times DF_i \times EF_i \times t_{i,drilling}$$

where $E_{basin,avg}$ is the emissions of the basin average well of a particular pollutant [tons/well], i is a particular engine on a drill rig (e.g. draw works, mud pump), LF_i is the load factor of engine i on a drill rig [%], HP_i is the horsepower of engine i on a drill rig [hp], DF_i is the deterioration factor of engine i on a drill rig, EF_i is the emissions factor of a particular pollutant of engine i on a drill rig [g/bhp-hr], and $t_{i,drilling}$ is the total drilling time (or fraction of total drilling time) of engine i on a drill rig [hr].

The emissions factors for NOx, SOx, VOC and CO were obtained from a variety of sources. In some instances the producers had direct measurements of the emissions factors of in-use equipment and provided these. In other instances the manufacturers rated emissions factors for a specific engine model and horsepower were used. If manufacturers rated emissions factors were used, it was necessary to account for deterioration of the equipment and the assumption was made that the equipment would be fully deteriorated as indicated by the manufacturers. The deterioration factors are a direct multiplier of the emissions factors, and were determined by using the deterioration model contained in the U.S. EPA's NONROAD2005 model for diesel non-road equipment (EPA, 2005a). It was assumed that the deterioration factors were those of baseline (or Tier 0) equipment – that is, before the introduction of federal standards regulating non-road engine emissions (EPA, 2005b). This is consistent with producer information indicating that drilling rigs are in service for many years before being upgraded, or rebuilt, at which point their emissions characteristics would be expected to change. However, the issue of deterioration factors should be further investigated in any future emissions inventory effort. The deterioration factors for each pollutant are shown in Table 2-1.

Table 2-1. Deterioration factors for drilling rig engines from EPA's NONROAD2005 model.

Pollutant	Deterioration Factor[a]
NOx	1.024
VOC	1.047
CO	1.185
PM	1.473

a - Note that deterioration factors are applied to the Tier level of each engine type for purposes on calculating emissions

The emissions factors for SOx were not subject to deterioration, as they are a direct function of the sulfur content of the fuel. The sulfur content of the fuel was determined from a survey conducted by WRAP in which individual counties responded with information about seasonal sulfur content in the non-road diesel fuel (Pollack, A.; Chan, L.; Chandraker, P.; Grant, J.; Lindhjem, C.; Rao, S.; Russell, J.; Tran, C., 2006).

Using the state OGC database of all wells drilled in 2002 and the depths to which the wells were drilled in the basin, $E_{basin,avg}$ was scaled on the basis of depth for each well in the basin and summed to obtain the total basin emissions from drilling rig activities. This calculation is shown below in Equation 2-2.

Equation 2-2:

$$E_{basin,total} = \sum_j E_{basin,avg} \times \left(\frac{d_j}{d_{avg}} \right)$$

where $E_{basin,total}$ is the total drilling rig emissions in a basin [tpy], $E_{basin,avg}$ is the emissions from an average well in the basin [tons/well], j is a well in the basin, d_j is the depth of well j in the basin [ft], and d_{avg} is the depth of an average well in the basin [ft]. The variation in depth of wells in a basin will affect the duration of drilling activity for each well. By using the producer reported average well depth and scaling this by the actual well depth of other wells, this methodology corrects for the varying drilling times of all wells in a basin.

The location of individual wells in a basin is determined on a county level, and the emissions totals for the basins are apportioned to each county in the basin on the basis of drilling spud count in that county. In some instances, counties are completely located within a basin. In other instances, portions of the county may be located in another focus basin, or in a basin for which no revised 2002 emission inventory estimates were made. In such a case the fractional spud count in the focus basin is used to determine the fraction of the county's emissions that are updated using this methodology. Finally, all counties in a state are summed to generate state total emissions from drilling rigs.

Table 2-2 summarizes the results of this analysis for all states in the WRAP region, which includes New Mexico, Arizona, Nevada, California, Utah, Colorado, Wyoming, North Dakota, South Dakota, Montana, Idaho, Oregon, Washington, and Alaska. California, as mentioned above, was excluded from this analysis. No drilling activity occurs in Idaho or Washington. As can be seen in Table 2-2, by far the largest NOx emissions from drilling activities are in New Mexico and Wyoming with Colorado following. North Dakota and Montana both have greater than 1,000 tons per year NOx emissions from drilling in 2002. SOx emissions do not correlate directly to NOx emissions – for example in Wyoming SOx emissions are 150 tons per year, less than half those of North Dakota – although North Dakota has three times less NOx emissions. The SOx emissions are driven both by drilling activity and the sulfur content of the non-road fuel in that state. In Wyoming, some efforts have been made to begin regulating the use of low-sulfur diesel fuel for non-road applications.

Table 2-2. Drilling rig emissions by state in the WRAP region in 2002.

State	Drill Rig Emissions [tpy] NOx 2002	SOx 2002	VOC 2002
Alaska	877	66	0
Arizona	0	0	0
Colorado	2,803	118	101
Montana	1,046	225	0
Nevada	24	1	0
New Mexico	5,476	244	68
North Dakota	1,536	358	0
Oregon	0	0	0
South Dakota	29	6	0
Utah	334	17	12
Wyoming	4,997	150	228
WRAP Total	17,123	1,185	410

Wellhead Gas Compressor Engine Emissions

The focus of the area source compressor engine emission estimate was the group of relatively small, dispersed wellhead compressor engines. The Phase I work represented the first effort to inventory these engines in most of the western states included in the WRAP region. Only two of the natural gas producing states had made previous efforts to inventory wellhead compressor engines. The results of the Phase I work indicated that these engines were a major contributor to the total O&G area source NOx emissions, and thus were one of the two sources updated in this analysis.

The Phase I work estimated emissions from compressor engines by generating a production-based emission factor from a local study of compressor engine emissions conducted by the New Mexico Oil and Gas Association (NMOGA) in the San Juan Basin of Northern New Mexico. The WRAP regional wellhead compressor emissions totals for each state were generated by scaling this production-based emissions factor by local gas production statistics. Implicit in this analysis were assumptions regarding the usage of wellhead compressors at individual well sites, based upon the fractional usage in the San Juan Basin.

The current analysis reviewed the previous Phase I methodology, and made use of the survey sent to major O&G production companies to compile basin-by-basin information about wellhead compressors and their emissions. The goal of this methodology was to move from a production-based emissions factor (EF) to a well count-based EF. This was considered more accurate because a count-based EF allowed for a calculation of emissions that used activity information about the engine, including the expected load in a basin, as well as accounting for variations in the equipment and typical configuration in each basin. In order to develop count-based wellhead compressor emissions estimates, it was necessary to determine the number of wellhead compressors in each basin as a fraction of the total number of wells in that basin. The specific information on wellhead compressors requested from major O&G producers in the survey was:

Based on Table 2-3 it was determined that lateral compressors would be included in all state point source inventories except for South and North Dakota and Utah. The lateral compressors in these states were accounted for in the Phase I work, and thus were not modified in this analysis. It should be noted that based on Table 2-3, it was determined that wellhead compressors in Colorado were counted in that state's point source inventory, since the inventory threshold was 2 tons per year actual emissions. In Alaska, wellhead compressor emissions were not estimated because all compressor sources are permitted by the state and thus included in the point source inventory.

The information provided by the O&G producers contacted in the data survey was used to determine the basin-wide and county-wide wellhead compressor emissions. The emissions estimates were conducted following Equation 2-3.

Equation 2-3:

$$E_{county,wellhead} = \%_{wellhead} \times N_{basin,county} \times (Activity \times Load_{wellhead} \times EF_{wellhead} \times DF_{wellhead} HP_{wellhead})$$

where $E_{county,wellhead}$ is the county-wide emissions of a pollutant from wellhead compressors [tpy], $\%_{wellhead}$ is the fraction of wells in a basin that have a wellhead compressor at the well site [%], $N_{basin,county}$ is the number of wells in a basin that lie within a particular county's boundaries, *Activity* is the number of hours per year that wellhead compressors are operating [hr/yr], $Load_{wellhead}$ is the load on the wellhead compressor engines in each basin, $EF_{wellhead}$ is the emissions factor of a representative wellhead compressor engine in a basin [g/bhp-hr], $DF_{wellhead}$ is the deterioration factor of the representative wellhead compressor engine in a basin, and $HP_{wellhead}$ is the average horsepower of a representative wellhead compressor in each basin [hp]. *Activity* was assumed to be 24 hours per day, 365 days per year, or 8760 hours per year. This is a conservative assumption, but is a permitting requirement for estimating emissions in several states. Due to the lack of detailed information from producers on actual operating hours per year and any down-time of compressors, it is recommended that the operating hours and load factors be reviewed in more detail in any future emissions inventory effort.

It should be noted that $N_{basin,county}$ was determined by intersecting the boundaries of the basin with those of the county. Where a county was located in multiple focus basins, or multiple basins that included a focus basin and a basin not considered, the fraction of the wells located in the focus basin was used to generate the emissions. The well locations were obtained from state OGC databases of all wells in the state. The activity for all compressors was assumed to be 24 hours per day, 365 days per year, since information from producers indicated that no compressors were removed from operation for a significant length of time. More detailed producer data would be needed to quantify the exact amount of time that wellhead compressor engines are not in service in any particular basin, but this information was not obtained as part of the survey process. Similarly to drilling rigs, $EF_{wellhead}$ was determined from manufacturers rated emissions factors provided by the O&G producers but was also multiplied by the appropriate deterioration factor. Based on conversations with the O&G producers it was determined that wellhead compressors are often used in the field for decades, and thus were assumed to be fully deteriorated. The EPA's NONROAD2005 model was used to determine the deterioration factors, where it was assumed that all wellhead compressors were natural gas-fired spark-ignited

1) How many wells does the producer operate within each basin in which they operate (number of wells and in which basin these wells are located)?
2) What fraction of the number of wells in each basin in which the producer operates use wellhead compressors, what fraction use lateral compressors, and what fraction use centralized compressors?
3) What is the average load on a wellhead and/or lateral compressor engine as a basin-wide average for each basin in which the producer operates?
4) What are the three most commonly used makes and models of wellhead and/or lateral compressors in each basin in which the producer operates?
5) What are the manufacturers' rated emissions factors of NOx, CO, and VOC for each of the makes and models of compressor engines identified?

Based on the responses of producers, and detailed conversations with each major producer, it was determined that wellhead compressor usage, equipment type, and typical operating load vary widely from basin to basin. Thus the Phase I assumption of a single production-based EF using San Juan Basin information was determined to be inaccurate. The San Juan South Basin in New Mexico has a high fraction of well-head usage whereas other basins did not – this is mainly driven by the need for well-site compression to boost field pressures sufficiently for transmission to pipelines. In virgin or newly developed fields and basins the field pressures are sufficiently high that far fewer wellhead compressors are required to generate this pressure than in mature fields and basins. The only exceptions to this general rule are basins with significant coal-bed methane (CBM) wells, which often have low gas pressures and require more wellhead compression; although even in these CBM fields and basins the usage of wellhead compression is generally no more than 5% of total wells.

In addition to determining the fraction of wellhead compressors, it was necessary to determine the fraction of lateral compressors and whether these compressors should be counted in the area source emissions inventory for each state. Lateral compressors are also natural gas-fired compressors that serve to boost field pressures for delivery to transmission pipelines, but they typically serve multiple well-sites simultaneously. These compressors are therefore larger than wellhead compressors and may have sufficient annual emissions of NOx that they are counted in point source inventories (and thus are not considered area sources according to this analysis). Table 2-3 below lists the annual emissions thresholds of an individual source to be included in each state's point source inventory.

Table 2-3. Summary of state point source inventory thresholds (PTE = Potential to Emit).

State	Point Source Inventory Threshold
Alaska	PTE 100 TPY
Arizona	PTE 40 TPY
Colorado	2 TPY actual emissions
Montana	PTE 25 TPY
New Mexico	PTE 25 TPY
North Dakota	PTE 100 TPY
Nevada	PTE 5 TPY
Oregon	PTE 100 TPY
South Dakota	PTE 100 TPY
Utah	PTE 100 TPY
Wyoming	PTE 25 TPY

compressor engines (EPA, 2005a). Table 2-4 below shows the deterioration factors for compressor engines.

Table 2-4. Deterioration factors for compressor engines from EPA's NONROAD2005 model.

Pollutant	Deterioration Factor
NOx	1.03
VOC	1.26
CO	1.35
PM	1.26

In basins for which more than one representative wellhead compressor engine make and model were provided, well counts in the basin were evenly divided among the compressor engine models. The fractions of wells in a basin that were equipped with wellhead compressors are summarized in Table 2-5 for each of the focus basins considered in this analysis.

Table 2-5. Fraction of wells with wellhead compressors in each basin of focused interest.

Basin	Wellhead Fraction
Southwestern Wyoming (Green River) Basin	0.4%
Wind River Basin	0.4%
Big Horn Basin	0.7%
Powder River Basin	4.5%
Uinta-Piceance Basin (UT)	5.0%
Paradox Basin	5.0%
San Juan Basin (South)[a]	20.4%
Permian Basin	2.2%

a – San Juan Basin (North) in Colorado was not included because Colorado wellhead compressors are included in the Colorado state point source inventory

Similarly to drilling rigs, the county-level wellhead compressor emissions estimates for 2002 were summed for all the counties in a state to generate state-level emissions estimates from wellhead compressors. It should be noted that for basins which were not in the focus list, the wellhead compression emissions were unchanged from the Phase I work, and thus were still based on gas production. Thus some state emissions totals represent emissions calculated using both the updated methodology and the previous Phase I methodology. Table 2-6 below shows the total estimated emissions from wellhead compressors in each state in the WRAP region.

Table 2-6. Estimated 2002 wellhead compressor engine emissions by state in the WRAP region.

State	Compressor Emissions (tpy)	
	NOx	SOx
Alaska[a]		
Arizona	8	0
Colorado[b]		
Montana	1,791	0

State	Compressor Emissions (tpy)	
	NOx	SOx
Nevada	33	0
New Mexico	35,140	1
North Dakota	2,920	0
Oregon	73	0
South Dakota	284	0
Utah	843	0
Wyoming	1,791	0
WRAP Total	46,154	1

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory
b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

As can be seen in Table 2-6, by far the largest emissions of NOx from wellhead compressors are in New Mexico, and this is largely due to the high fractional use of wellhead compressors in the San Juan Basin. Note that North Dakota, South Dakota, Nevada and Oregon emissions were not updated from Phase I. Montana compressor emissions represent only a partial update, since only those counties within the Big Horn Basin and Powder River Basin were updated in Montana. The only source of SOx emissions from compressors is from New Mexico, where specific information was available from major O&G producers on H_2S levels in the gas. We did not have the resources to investigate whether there may be other basins with significant H_2S content in the gas produced, and hence in the compressor emissions.

NMED Inventory

The NMED ozone precursors study contains a complete EI analysis conducted for San Juan and Rio Arriba counties in New Mexico in 2002, and constitutes a complete set of data that supersede any other estimate for emissions in these counties (Pollack, A.; Russell, J.; Grant, J.; Friesen, R.; Fields, P.; Wolf, M. 2006). The focused inventory developed by ENVIRON for NMED covered only those O&G area sources located within San Juan and Rio Arriba counties in New Mexico for calendar year 2002. The methodology used was similar to the analysis conducted here, and relied on a survey of major producers in these counties to derive a count-based inventory of O&G equipment from which an emissions inventory could be conducted. Because the geographic region of interest was smaller than the WRAP region considered here, greater resources could be utilized to develop a detailed and accurate EI for these two counties. Thus all emissions estimates made in this work were used to replace any emissions previously estimated for these two counties. There were several equipment types that were identified to be in use in this study which had not been previously considered. Two such equipment types were salt water disposal (SWD) engines, and artificial lift engines. These two source categories were added to the 2002 EI, although their emissions are limited to these two counties in New Mexico.

The NMED ozone precursors study estimates for oil and gas area source emissions in 2002 in San Juan and Rio Arriba counties are compared to these estimates from the WRAP Phase I work in Tables 2-7 and 2-8 below.

Table 2-7. Emissions totals (tpy) for various oil and gas area source categories for San Juan and Rio Arriba counties from the NMED ozone precursors study.

Category	NOx		SOx		VOC	
	Rio Arriba	San Juan	Rio Arriba	San Juan	Rio Arriba	San Juan
Compressor Engines	11,279	16,042	0	1	1,079	1,981
Drill Rig Emissions	497	697	28	37	12	17
Artificial Lift emissions	166	298	0	0	3	6
SWD Engines	62	43	0	0	4	2
Gas Wells	2,412	3,790	2	3	47,415	57,570
Oil Wells	63	146	0	0	381	601

Table 2-8. Emissions totals (tpy) for various oil and gas area source categories for San Juan and Rio Arriba counties from the WRAP Phase I emissions inventory.

Category	NOx		SOx		VOC	
	Rio Arriba	San Juan	Rio Arriba	San Juan	Rio Arriba	San Juan
Compressor Engines	9,136	14,907				
Drill Rig Emissions	1,331	1,671	289	363		
CBM Emissions	48	94				
Gas Wells	2,406	3,039			19,925	33,154
Oil Wells	1	1			186	145

As can be seen from the comparison of Tables 2-7 and 2-8, the more detailed NMED study resulted in different estimates for NOx, SOx and VOC than the WRAP Phase I. Compressor engine NOx emissions increased in the NMED study because a more accurate count of compressor engines was possible for these two counties, however drilling rig NOx emissions decreased due to a better estimate of actual drilling time. VOC emissions increased significantly, by approximately 51,000 tpy (a 98% increase) due mainly to an improved estimate of gas well venting processes, and fugitive emissions from gas wells.

Southern Ute Tribal Inventory

The Southern Ute Indian Tribe emission inventory was developed in order to meet certain federal Environmental Protection Agency (EPA) reporting requirements and to meet internal tribal inventory requirements (Lee, C., 2005). The Southern Ute Indian Tribal Reservation occupies land in Archuleta and La Plata counties in Colorado. The inventory considered all major area source O&G emissions categories except drilling activities on the Southern Ute lands. This included wellhead compression, CBM pump engines, and other wellhead activities and included estimates of NOx, VOC, CO and PM emissions (Lee, C., 2005). In order to integrate this inventory with the updated 2002 EI, the emissions associated with wells located in the Southern Ute land were removed from the 2002 EI, and the Southern Ute EI estimates were added to replace them. In order to do this, the boundaries of the Southern Ute land were intersected with the two counties in Colorado, and the fraction of wells in each county that lie inside and outside the Southern Ute land were determined. These fractions were used to scale down emissions from the 2002 EI in each source category estimated by the Southern Ute Inventory in order to remove these emissions from the 2002 EI. Once emissions from the 2002 EI were removed, the Southern Ute Inventory estimates were added for each source category. It should be noted that drilling rig emissions for these two counties were not replaced in the 2002 EI, because they were not estimated by the Southern Ute Inventory. Rather it was verified that the Phase II estimates of drilling rig emissions would apply to all wells in Colorado, both on tribal and nontribal land.

Updated 2002 Emissions Inventory

The final emissions for 2002 in this current analysis were estimated by compiling the updated emissions for compressors and drilling rigs in the focus basins, by integrating the NMED ozone precursors study emissions for San Juan and Rio Arriba counties in New Mexico, by integrating the Southern Ute Tribal inventory, and finally by integrating the original Phase I inventory for all sources that were not updated. The results of the 2002 updated EI for the WRAP region is shown below in Table 2-9 for NOx emissions and Table 2-10 for SOx emissions. This table also includes, for comparison, the oil and gas point sources for each state from the current WRAP emissions inventory, and the total of oil and gas area and point sources.

Table 2-9. Updated 2002 EI showing NOx emissions (tpy) for all states.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	877	0		9		886	45,431	46,317
Arizona		0	8	9		17	642	659
California						8,070	10,809	18,879
Colorado[b]	2,803	9	3,271	15,946	1,489	23,518	25,219	48,737
Idaho							2,590	2,590
Montana	1,046	42	1,791	4,678		7,557	3,996	11,553
Nevada	24	1	33	4		62	83	145
New Mexico	5,476	329	35,140	14,602	92	55,640	56,900	112,540
North Dakota	1,536	75	2,920	101		4,631	4,638	9,269
Oregon		0	73	12		85	1,182	1,267
South Dakota	29	3	284	44		361	323	684
Utah	334	31	843	2,127		3,335	3,049	6,384
Washington							480	480
Wyoming	4,997	111	1,791	6,398	1,428	14,725	13,423	28,148
WRAP Total	17,123	603	46,154	43,929	3,008	118,887	168,765	287,652

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory
b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

Table 2-10. Updated 2002 EI showing SOx emissions (tpy) for all states.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	66	0		0		66	773	839
Arizona		0	0	0		0	0	0
California						57	887	944
Colorado[b]	118	0	0	0	0	118	91	209
Idaho							7	7
Montana	225	0	0	0		225	11	236
Nevada	1	0	0	0		1	0	1
New Mexico	244	0	1	5	0	250	13,675	13,925
North	358	0	0	0		358	2,944	3,302

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Dakota								
Oregon		0	0	0		0	8	8
South Dakota	6	0	0	0		6	10	16
Utah	17	0	0	0	0	17	0	17
Washington							8	8
Wyoming	150	0	0	0	0	150	12,188	12,338
WRAP Total	1,185	0	1	5	0	1,248	30,602	31,850

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory
b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

Comparison of Phase I and Phase II 2002 Estimates

The oil and gas area source emissions estimates from the Phase II work are compared to the estimates of the Phase I work. Figure 2-2 below shows the comparison of 2002 NOx oil and gas area source emissions from these two analyses, and Figure 2-3 below shows the comparison of 2002 oil and gas area source SOx emissions from these two analyses. As can be seen from Figure 2-2, both Utah and Wyoming show a substantial percent reduction in NOx emissions from the Phase I and II analyses. This is largely due to a revised estimate of the fraction of wells using wellhead compression in these two states as discussed above. In addition, the well count-based emissions estimates for compressor engines removed the inaccurate Phase I assumption that all gas production would have an associated emissions factor for gas equipment source categories. Incidental gas production from a well producing mainly oil does not typically have gas equipment installed at the well site. It should be noted that for Colorado, the addition of wellhead compressor emissions on Southern Ute Tribal land represented the only wellhead compressor emissions for that state, since all other wellhead compressors fall within Colorado's point source inventory.

As can be seen from Figure 2-3, drilling rig emissions in Wyoming, Colorado, New Mexico and Utah were all updated in this current analysis because the focus basins are largely in these states. The revised estimates of drilling time are substantially lower than the times estimated in the Phase I analysis using spud and completion dates. This reflects the fact that completion activities often take a significant amount of time but the drilling rigs are not expected to be in operation during that time.

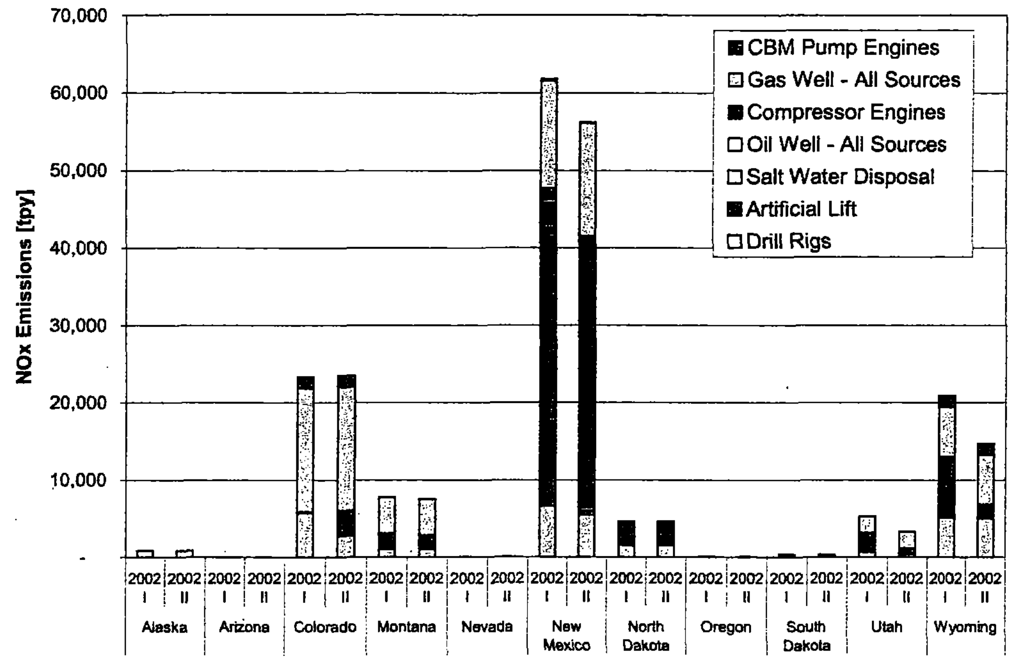


Figure 2-2. Comparison of 2002 state total oil and gas area source NOx emissions from Phase I and Phase II analyses.

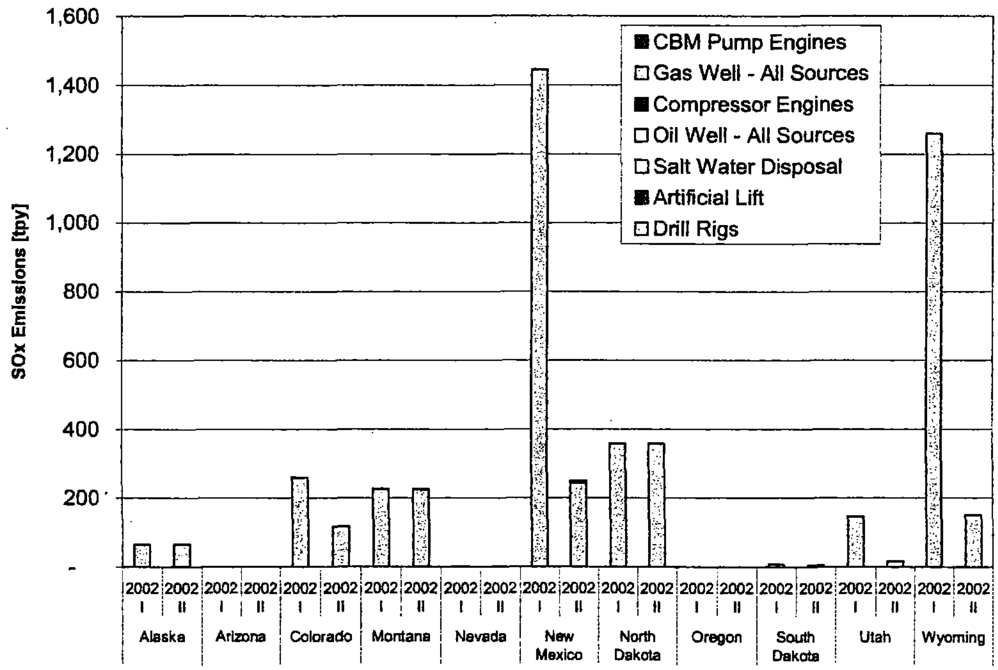


Figure 2-3. Comparison of 2002 state total oil and gas area source SOx emissions from Phase I and Phase II analyses.

3. UPDATING BASELINE EMISSIONS FROM 2002 to 2005

The second major task in this project was to update the baseline EI, from which projections to 2018 are made, from 2002 to 2005. This was considered a valuable addition to this analysis because any future projections would be able to incorporate the tremendous growth in O & G activity in the western United States that has occurred between 2002 and 2005. The number of drilling permits alone issued by the Federal Bureau of Land Management in the Rocky Mountain area has nearly doubled between 2002 and 2005 (Talhelm, J., 2006). 2005 would serve as an additional data point against which to calibrate estimated emissions projections to 2018, and to verify the accuracy of data sources that predict 2005 O&G activity. In addition, there have been increasing efforts by state environment departments and by the state OGCs to maintain more accurate records of O&G activity and to make those records publicly available (Madison, C., Schlichtemeier, C., 2007, Carlin, J., 2007). Thus using 2005 well-specific data for each state would make use of this improved database of information.

The update of the baseline EI from 2002 to 2005 involved utilizing and combining these two sources of information:

- State OGC well-specific databases
- State OGC databases of wells spudded (drilling records)

The state OGC databases contain lists of wells, the locations of the wells by latitude/longitude and by county, oil and gas production from each well (where applicable), and the well status which includes whether the well is still active and whether the well is a CBM well. The state OGC drilling records indicate the date that a well is spudded – indicating that drilling has begun – the date that the well was completed, and the location of the spud.

The methodology used in this task was to derive scaling factors on the basis of the state OGC databases for spuds and well location and production. These scaling factors were estimated on a county-level basis for each state, and applied to the 2002 EI discussed in Section 3 of this report to generate a new 2005 EI.

Scaling Based on State OGC Databases

Several scaling factors were derived for scaling 2002 to 2005 emissions by source category and by county for the WRAP region. Scaling factors were derived separately for drilling, count-based compressor emissions, count-based other wellhead emissions, gas-production-based emissions, and oil-production-based emissions. Each type of scaling factor is described below.

Drilling scaling factors were determined by looking at drilling records maintained by state OGCs. These records give an indication of the number of wells spudded in each county for 2005. Spudding indicates the beginning of drilling at that well site. It was assumed that all wells spudded in 2005 would be completed by 2005 and were thus considered a single drilling event. All 2002 county-level emissions generated in the previous task were scaled by the ratio of 2005 number of wells spudded in that county to 2002 number of wells spudded in that county. Two special cases of drilling scaling factors were considered. If no new wells were drilled in 2005 in counties for which there was active drilling in 2002, the drilling emissions scaling factor was assumed to be zero for that county. In counties where no drilling occurred in 2002 but drilling did occur in 2005, a different method was employed to generate a scaling factor. The 2002 state average emissions per well was determined from the 2002 EI update conducted in the previous task, and then this emissions per well was multiplied by the number of wells drilled in that county in 2005.

Count-based scaling factors were used to scale emissions categories that were updated in this analysis on the basis of count, and those emissions categories that were estimated on a count basis but not updated from the previous Phase I work. If counties were only partially in a focus basin that was updated in this analysis, the fraction of the total well count in that county intersecting the basin boundaries was used to scale the emissions correspondingly. Frequently the state OGC databases do not indicate whether a well is an oil well or a gas well. This is important because this analysis makes the assumption that oil wells do not have gas-producing equipment at the well site and vice versa. Many wells produce both oil and gas, and the ratio of the annual production of gas to oil, known as the gas-oil ratio (GOR), was used to determine whether a well is an oil or gas well. If the oil production or gas production was zero, the well could easily be labeled an oil or gas well. Where both gas and oil production exists, the count of wells by GOR was plotted to determine a reasonable cut-off GOR below which the well would be classified as an oil well. An example plot is shown here for New Mexico in Figure 3-1. The GOR distribution was seen to be roughly bimodal with a cut-off GOR of 0.1, below which wells were considered to be oil wells and above which wells were considered to be gas wells. For all emissions source categories that were scaled on a count basis, the 2005 emissions were generated by multiplying the 2002 emissions of that source category by the ratio of the 2005 well count to the 2002 well count.

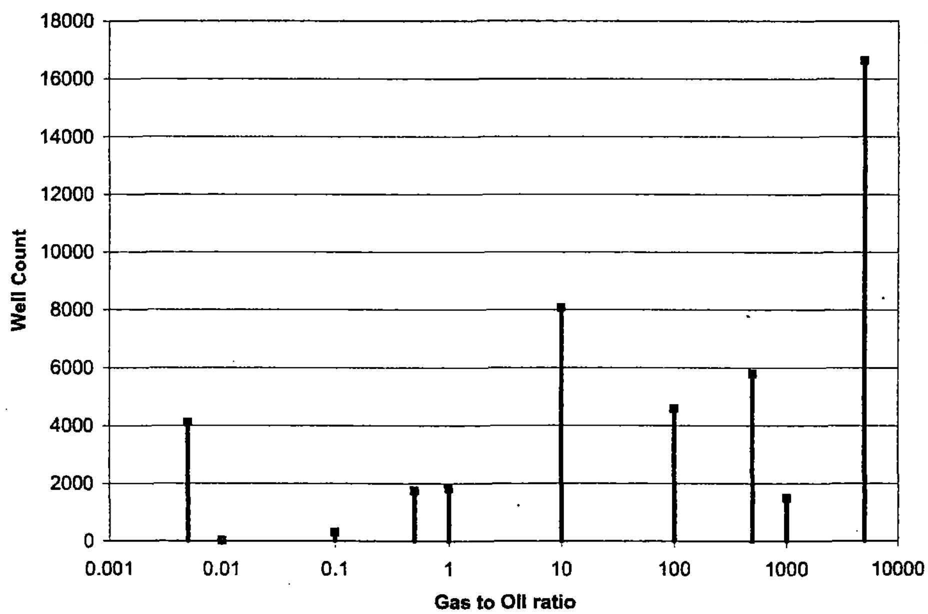


Figure 3-1. New Mexico GOR as a function of well count for 2005.

Production based scaling factors were derived for both oil-based and gas-based emissions source categories in a manner similar to the count-based approach described above. This was necessary for all source categories that were not updated from the previous Phase I inventory.

The scaling factors were applied to the 2002 EI in order to generate 2005 emissions. Tables 3-1 and 4-2 show the updated NOx and SOx emissions respectively from drilling rigs and wellhead compressor engines for 2002 and 2005 for all states.

Table 3-1. NOx emissions from drilling rigs and wellhead compressor engines in 2002 and 2005, and change (in tons) and percentage change in NOx emissions from 2002 to 2005.

	Drill Rig Emissions				Compressor Emissions			
	NOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005	NOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005
State	2002	2005			2002	2005		
Alaska	877	835	-42	-5%				
Arizona	0	0	0	0%	8	6	-2	-25%
Colorado[a]	2,803	8,000	+5,197	+185%	3,271	3,302	+31	+1%
Montana	1,046	3,007	+1,961	+187%	1,791	2,267	+476	+27%
Nevada	24	37	+13	+54%	33	33	0	0%
New Mexico	5,476	8,640	+3,164	+58%	35,140	35,345	+205	+1%
North Dakota	1,536	3,055	+1,519	+99%	2,920	2,799	-121	-4%
Oregon	0	0	0		73	51	-22	-30%
South Dakota	29	203	+174	+600%	284	305	+21	+7%
Utah	334	2,888	+2,554	+765%	843	996	+153	+18%
Wyoming	4,997	15,783	+10,786	+216%	1,791	3,288	+1,497	+84%
WRAP Total	**17,123**	**42,448**			**46,154**	**48,393**		

a – Wellhead compressor emissions in Colorado are only those located on Southern Ute Tribal land; all other wellhead compressors are assumed to be part of Colorado's point source inventory and thus are not listed here.

Table 3-2. SOx emissions from drilling rigs and wellhead compressor engines in 2002 and 2005, and change (in tons) and percentage change in SOx emissions from 2002 to 2005.

	Drill Rig Emissions				Compressor Emissions			
	SOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005	SOx [tpy]		Change 2002 to 2005 [tpy]	% Change 2002 to 2005
State	2002	2005			2002	2005		
Alaska	66	62	-4	-6%				
Arizona	0	0	0		0	0	0	0%
Colorado[a]	118	350	+232	+197%	0	0	0	0%
Montana	225	640	+415	+184%	0	0	0	0%
Nevada	1	1	0	0%	0	0	0	0%
New Mexico	244	362	+118	+48%	1	1	0	0%
North Dakota	358	688	+330	+92%	0	0	0	0%
Oregon	0	0	0		0	0	0	0%
South Dakota	6	43	+37	+617%	0	0	0	0%
Utah	17	149	+132	+776%	0	0	0	0%
Wyoming	150	541	+391	+260%	0	0	0	0%
WRAP Total	**1,185**	**2,835**			**1**	**1**		

a – Wellhead compressor emissions in Colorado are only those located on Southern Ute Tribal land; all other wellhead compressors are assumed to be part of Colorado's point source inventory and thus are not listed here.

Table 3-1 shows that NOx emissions from drilling rigs increased dramatically in Wyoming, North Dakota, Montana and Colorado, in terms of total tonnage of NOx emissions. This reflects the increased exploration activity occurring in these states between 2002 and 2005. It should be noted that what is presented in tables 3-1 and 3-2 above are state total emissions, and thus it is not possible from this information to determine which basin's activities contributed to this state total. Wellhead compressor NOx emissions are not seen to increase significantly in most of these states from 2002 to 2005, and have decreased in some states as wells are plugged and abandoned and no new producing wells have been added. Wellhead compressors are only used on a relatively small fraction of new wells in most of these states, thus even a large growth in number of wells in these three years would not produce a major growth in emissions. In addition, during the initial years of life of a new producing gas well, wellhead compression is often not needed to boost pressure for transmission. In the San Juan Basin in New Mexico, which has a high usage of wellhead compressors, there was not a significant growth in the number of new producing wells developed between 2002 and 2005. However, in Wyoming the rapid growth in development of the Powder River Basin, where approximately 5% of wells have wellhead compressors, leads to a near doubling of emissions from wellhead compressors. It should be noted that Colorado's wellhead compressor emissions are only derived from the Southern Ute Tribal Inventory. All other wellhead compressors are already captured by Colorado's point source inventory and thus not included here.

4. CONTROL STRATEGY EVALUATION

Under this task, potential control technologies were evaluated, that can be applied to the sources of NOx, PM, SOx and VOC as listed in Table 4-1.

Table 4-1. Control technology evaluations conducted.

Equipment	NOx	PM	SOx	VOC
Drill Rigs	X	X	X	
Compressor Engines	X	X		
Tanks				X
Glycol Dehydration Units				X
Pneumatic Devices				X
Completion-Flaring and Venting				X

For each of the sources identified in Table 4-1, a range of viable control options were evaluated. Included in these options were

- Engine modifications (e.g., lean-burn engines, ignition timing, exhaust gas recirculation)
- After treatment control devices (e.g., catalysts, diesel particulate filters)
- Engine replacement/repowering
- Various methods for reducing VOCs from exploration and production activities

The information developed under this task is provided in a series of White Papers that are contained at the end of this chapter. It should be noted again that the focus of this study was smaller area sources of emissions from oil and gas operations that are not currently included in the point source emission inventories for each of the states in the WRAP region. Therefore, most if not all equipment evaluated is equipment found at the well head and possibly from smaller lateral compressor operations.

For each control option, the control technology and the application of each technology to types of equipment identified in Table 4-1 were described. The range of control efficiencies, the potential emissions reductions, and the range of costs and cost-effectiveness and the potential for applying the controls to existing equipment (i.e., retrofit applications) and new equipment was determined for each application. The potential emissions reductions were determined by applying the control efficiencies to representative equipment identified in each basin and described earlier in this report. The cost-effectiveness was determined using the methodology adopted by the California Air Resources Board (CARB) in its evaluation of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines (CARB, 2001a), which is described in detail below. The cost-effectiveness was determined by dividing the annualized cost by the ton of pollutants reduced from representative equipment found for these operations. While the White Papers were developed for controlling various exploration and production activities, resources did not allow the determination of potential emissions reductions. Therefore, the cost of control equipment was determined for these sources but the cost-effectiveness was determined only for drill rigs and compressor engines. It should be noted that the costs used for this report were not indexed to 2007 dollars.

It should be emphasized that there are multiple variables to be considered in calculating the cost and operational needs of individual control technologies. Many technologies require testing and evaluation in the settings where they have previously not been applied. At the same time, these technologies have been tested and are in use in other oil and gas fields. This report presents estimates of the effectiveness of these technologies as they have been tested and applied to date. These control technologies would very likely receive additional analyses before being adopted into a regulation or permit by a regulatory agency.

COMPRESSOR ENGINES

The combustion of fuels in oil and gas compression operations results in emissions of NOx, CO, VOC, fine particulate matter (PM_{10}) and sulfur oxides (SOx). Because most oil and gas compressor engines operate on natural gas, the primary pollutant of concern is NOx. While the effort for this study was focused on visibility pollutants, the reductions of particulate matter were not evaluated because emissions are minimal due to the use of natural gas as a fuel. Because PM emissions from natural gas-fired compressors are expected to be very small, information on PM emissions factors was not easily available. Sulfur dioxide emission reductions were not evaluated because information obtained from compressor operators indicated that only low sulfur content natural gas is used in compressor engines (Smith, G.R., BP America Inc., 2007, Stewart, D., Encana Corp., 2007). Therefore, the NOx reduction potential and the cost-effectiveness were estimated for a range of well head compressor engines across the WRAP region. Based on this study, the majority of wellhead compressor engines ranged in size from 50 hp – 300 hp. In some basins, operators reported wellhead compressors in excess of 300 hp.

Most compressor engines at the well head are spark ignition (SI) internal combustion engines. SI engines typically are fueled with natural gas or volatile liquid fuels, such as gasoline. Because SI engines fired on natural gas are the primary source of compressor engine emissions in oil and gas operations, we focused on these engines for the purpose of evaluating potential control technologies or strategies. SI engines can operate under fuel-lean conditions or under stoichiometric to slightly fuel-rich conditions. Stoichiometric condition is defined as the condition when there is exactly enough free oxygen to combine with all of the fuel. Under this condition the mass ratio of air to fuel is considered a stoichiometric mixture. Most large SI engines (over about 1000 hp) are fuel-lean type engines while smaller engines (300 hp and less) are generally rich-burn stationary engines and are the primary source of emissions at natural gas production facilities.

Controls for compressor engines can be grouped into the following general categories: combustion modifications (or primary methods); fuel switching; post-combustion controls (or secondary methods); and replacement of the engine with a new, low emissions engine or electric motor. Combustion modifications can reduce NOx formation by changing the air/fuel mixture, reducing peak temperatures, or shortening the residence time at high temperatures. Emissions of CO and VOC are generally the result of incomplete combustion. They can be controlled by combustion modifications that increase oxygen, temperature, residence time at high temperatures and the mixing of air and fuel. It should be noted that some of these tend to increase NOx so care must be taken to assure that reductions in one pollutant do not increase the emissions of another pollutant. Where appropriate, the discussions in the White Papers that follow identify the impact of controlling NOx on the other pollutants. A summary of the compressor engine control technologies, control efficiency, NOx reductions and cost-effectiveness is shown Table 4-2.

Table 4-2. Summary of control technologies for compressor engines.

Measure No.	Control Measure Name[1]	Control Efficiency %	NOx Reduction (tpy)	Cost-Effectiveness ($/ton)
CE-1	NSCR	90 to 98	1.0 to 45.3	200 to 7,900
CE-2	AFR	10 to 40	0.3 to 12.1	100 to 2,500
CE-3	ITR	15 to 30	0.3 to 10.8	100 to 1,200
CE-4	AFR + ITR	10 to 40	0.3 to 12.1	100 to 3,600
CE-5	PSC	80	0.9 to 38.5	100 to 3,000
CE-6	L-E	80	0.9 to 38.5	100 to 2,600
CE-7	SCR	80	0.9 to 38.5	900 to 31,000
CE-8	Replace Engine[2]	60 to 100	0.9 to 38.5	100 to 4,700

1 NSCR - Non-selective catalytic reduction AFR - Air Fuel Ratio Control, ITR - Ignition Timing Retard, PSC - Prestratified Charge, L-E - Low Emission Engine, SCR - Selective Catalytic Reduction, EGR - Exhaust Gas Recirculation, CEC - Crankcase Emission Control, DPF - Diesel Particulate Filter, DOC - Diesel Oxidation Catalyst, LNC - Lean NOx Catalyst, NG - Natural Gas, VRU – Vapor Recovery Unit

2 Replace Engine with electrified engine does not include any potential impact from increases in central station power plants due to increased electrical load.

DRILL RIG ENGINES

Drilling for natural gas involves the use of drilling rigs that generally employ diesel fired engines as the power source. The type of drilling that occurs is known as rotary drilling, and consists of a sharp, rotating metal bit used to drill through the Earth's crust. This type of drilling is used primarily for deeper wells that that have high downhole pressures. Most rotary rigs require 1,000 to 3,000 hp, and when drilling in excess of 20,000 feet below the surface may require even more hp. The energy from these diesel engines is used to power the rotary equipment, the hoisting equipment, and the circulating equipment as well as incidental lighting, water, and compression requirements not associated directly with drilling. Hoisting equipment consists of tools used to raise and lower whatever other equipment may be used in the well. The most visible part is the derrick that extends vertically from the well hole. The derrick serves to support drilling cables and pulleys to lower and raise equipment. Circulating equipment consists of drilling fluid which is circulated down through the well hole during the drilling process and subsequently pumped up and out to remove the rock and other material that is drilled through. In addition to diesel engines, other types of engines such as natural gas or gasoline powered engines are also used, however much less frequently.

In estimating emissions from diesel engines used for drilling operations, it is important to note that once the well has been drilled, well completion activities are performed to allow the well to become productive. It is also important to note that other compounds and gases such as oil and water may be present and must be removed before the natural gas is sent through the pipeline. Well completion activities involve strengthening the well hole with casing, evaluating the pressure and temperature of the formation, and then installing the proper equipment to ensure proper flow of natural gas out of the well. These activities are not considered in the controls analysis and White Papers presented below for drilling rigs.

Based on this study, we found that drilling rig engines varied widely in activity as well as size. If multiple engines are present on a single rig, control is applied to all engines and the overall "rig" cost-effectiveness and NOx reduction potential reported. Individual drilling rig engine sizes in the regions studied varied from 200 hp – 1500 hp. Cost-effectiveness and NOx reduction potential is estimated for a range of drilling rigs found in this study across the WRAP region. A summary of the drilling rig engine control technologies, control efficiencies, NOx reductions and cost-effectiveness is shown in Table 4-3

Table 4-3. Summary of control technologies for drilling rigs.

Measure No.	Control Measure Name[1]	Control Efficiency %	NOx Reduction (tpy)	Cost-Effectiveness ($/ton)
DRE-1	ITR	15 to 30	6.6 to 17.2	1,000 to 2,200
DRE-2	SCR	80 to 95	25.8 to 66.8	3,000 to 7,700
DRE-3	EGR	40	11.8 to 30.6	800 to 2,000
DRE-7	LNC	10 to 20	4.4 to 11.5	1,400 to 3,400
DRE-8	Low S Diesel	14	TBD	TBD
DRE-8	NG	85 to 91	TBD	TBD
DRE-8	Emulsified Diesel	20	5.9 to 15.3	4,500 to 11,600
DRE-9	Tier 2 to Tier 4 Replacement	43 to 93	7.8 to 33.6	900 to 2,400
DRE-9	Tier 3 to Tier 4 Replacement	43 to 89	4.7 to 20.1	900 to 2,000

1 NSCR - Non-selective catalytic reduction AFR - Air Fuel Ratio Control, ITR - Ignition Timing Retard, PSC - Prestratified Charge, L-E - Low Emission Engine, SCR - Selective Catalytic Reduction, EGR - Exhaust Gas Recirculation, CEC - Crankcase Emission Control, DPF - Diesel Particulate Filter, DOC - Diesel Oxidation Catalyst, LNC - Lean NOx Catalyst, NG - Natural Gas, VRU – Vapor Recovery Unit

EXPLORATION AND PRODUCTION

Several measures for reducing emissions of volatile organic compounds at well head operations were identified. Many of these measures have been identified under the U. S. Environmental Protections Agency's (EPA) Natural Gas STAR Program, which is a flexible, voluntary partnership between EPA and the oil and natural gas industry. Through the Program, EPA works with companies that produce, process, and transmit and distribute natural gas to identify and promote the implementation of cost-effective technologies and practices to reduce emissions of methane, a potential greenhouse gas, and volatile organic compounds. Gas STAR promotes the use of these emission reduction technologies and practices through the program's Best Management Practices (BMPs) and other Technologies and Practices. Table 4-4 identifies several of these measures.

Table 4-4. Control measures for exploration and production activities.

Measure No.	Category	Control Measure Name	Pollutant	Control Efficiency (%)
EAP-1	Glycol Dehydration	Optimize Circulation	VOC	33 to 67
		Electric Pump	VOC	67
		Flash Tank	VOC	10 to 40
		Desiccant	VOC	99
EAP-2	Pneumatic Controls	Instrument Air	VOC	98
		Non-Bleed	VOC	98
EAP-3	Completion Venting and Flaring	Flaring	VOC	62 to 84
		Green Completion	VOC	70
EAP-4	Tanks	VRU	VOC	95
		Water Blanket	VOC	TBD

As described earlier, emissions reductions were not determined for these sources due to lack of resources. Recommendations for further work that would further quantify emissions from these operations are discussed later in this report.

METHODOLOGY FOR CONTROL TECHNOLOGY EVALUATION

To describe the methodology used to evaluate control technologies, we provide an example calculation of the cost-effectiveness for a drilling rig in Table 4-5.

Table 4-5. Example calculation of cost-effectiveness for drilling rig engine.

	CATERPILLAR D398	
	Baseline	**SCR**
Operating Fraction (%/yr)	0.75	0.75
Annual usage (hr/yr)	6,570	6,570
Annualized Capital Cost		$142,645
Useful Life (years)	10.0	10.0
NOx Emission Factor (g/bhp-hr)	8.94	1.12
VOC Emission Factor (g/bhp-hr)	0.11	0.11
Engine Size (bhp)	967	967
Avg. Load	0.68	0.68
NOx g/hr	5879	735
VOC g/hr	72	72
NOx tons/year	42.57	5.32
VOC tons/year	0.52	0.52
NOx Reduction tons/year		37.25
VOC Reduction tons/year		0.00
Annualized Cost-Effectiveness (NOx Only)		$3,829
Annualized Cost-Effectiveness (VOC Only)		N/A

From Table 4-5, we first determined the fraction of the year that the drilling rig was in operation, which in turn provided the annual usage for each representative engine. This fraction varied for each geographical area based on information provided by the producers. The annualized cost was then determined for each representative engine and averaged for each basin to estimate the annual costs for each control measure. The annualized cash flow method was used to determine annual cost. This method was applied to the pre-tax capital and installation costs using a nominal interest rate (including inflation) of 10 percent over a ten year life. In most cases, fuel costs were not included. The annual operation and maintenance costs attributable to the control method were added to the annualized cost. Where appropriate, the additional annual fuel cost was added. Costs for compliance including reporting and recordkeeping, permit applications and emissions testing were not included. Using emission factors described in earlier chapters, the total emissions were determined on an annual basis. Applying the control effectiveness for each control technology to the annual emissions, we were then able to calculate the annualized const-effectiveness as shown in Table 4-5

WHITE PAPERS

The following pages contain the White Papers for each control measure. It should be noted that the range of cost-effectiveness identified for each control measure represents the range for the size of equipment found in the areas studied and not necessarily for the entire range of equipment sizes identified in the cost tables.

Table 4-6. Summary of control options.

Measure No.	Category	Control Measure Name[1]	Pollutant	Control Efficiency %
CE-1	Compressor Engines-Rich Burn	NSCR	NOx	90 to 98
			CO	80
			HC	50
CE-2	Compressor Engines, SI and CI	AFR	NOx	10 to 40
CE-3	Compressor Engines, SI and CI	ITR	NOx	15 to 30
CE-4	Compressor Engines, SI and CI	AFR + ITR	NOx	10 to 40
CE-5	Compressor Engines, Rich Burn	PSC	NOx	80
CE-6	Compressor Engines, SI	L-E	NOx	80
CE-7	Compressor Engines, Lean Burn	SCR	NOx	80
CE-8	Compressor Engines, All	Replace Engine	NOx	60 to 100
DRE-1	Drilling Rig Engines	ITR	NOx	15 to 30
DRE-2	Drilling Rig Engines	SCR	NOx	80 to 95
DRE-3	Drilling Rig Engines	EGR	NOx	40
DRE-4	Drilling Rig Engines	CEC	PM	6 to 23
DRE-5	Drilling Rig Engines	DPF	PM	85
			CO	90
			HC	90
DRE-6	Drilling Rig Engines	DOC	PM	25
			CO	85
			HC	90
DRE-7	Drilling Rig Engines	LNC	NOx	10 to 20
DRE-8	Drilling Rig Engines	Low S	PM	14
		NG	NOx	85 to 90
			PM	50 to 80
		Emulsion	NOx	20
			PM	17
			CO	13
EAP-1	Glycol Dehydration	Optimize Circulation	VOC	33 to 67
		Electric Pump	VOC	67
		Flash Tank	VOC	10 to 40
EAP-2	Pneumatic Controls	Instrument Air	VOC	98

Measure No.	Category	Control Measure Name[1]	Pollutant	Control Efficiency %
		Non-Bleed	VOC	98
EAP-3	Completion Venting and Flaring	Flaring	VOC	62 to 84
		Green Completion	VOC	70
EAP-4	Tanks	VRU	VOC	95
		Water Blanket	VOC	TBD

NSCR - Non-selectic catalytic reduction
AFR - Air Fuel Ratio Control
ITR - Ignition Timing Retard
PSC - Prestratified Charge
L-E - Low Emission Engine
SCR - Selective Catalytic Reduction
EGR - Exhaust Gas Recirculation
CEC - Crankcase Emission Control
DPF - Diesel Particulate Filter
DOC - Diesel Oxidation Catalyst
LNC - Lean NOx Catalyst
NG - Natural Gas

Table 4-7. Summary of emissions reductions and cost-effectiveness.

Measure No.	Category	Control Measure Name	Control Efficiency %	NOx Reduction[1] (tpy)	Cost-Effectiveness[2] ($/ton)
CE-1	Compressor Engines-Rich Burn	NSCR	90 to 98	1.0 to 45.3	200 to 7,900
CE-2	Compressor Engines, SI and CI	AFR	10 to 40	0.3 to 12.1	100 to 2,500
CE-3	Compressor Engines, SI and CI	ITR	15 to 30	0.3 to 10.8	40 to 1,200
CE-4	Compressor Engines, SI and CI	AFR + ITR	10 to 40	0.3 to 12.1	100 to 3,600
CE-5	Compressor Engines, Rich Burn	PSC	80	0.9 to 38.5	100 to 3,000
CE-6	Compressor Engines, SI	L-E	80	0.9 to 38.5	100 to 2,600
CE-7	Compressor Engines, Lean Burn	SCR	80	0.9 to 38.5	900 to 31,000
CE-8	Compressor Engines, All	Replace Engine	60 to 100	0.9 to 38.5	100 to 4,700
DRE-1	Drilling Rig Engines	ITR	15 to 30	6.6 to 17.2	1,000 to 2,200
DRE-2	Drilling Rig Engines	SCR	80 to 95	25.8 to 66.8	3,000 to 7,700
DRE-3	Drilling Rig Engines	EGR	40	11.8 to 30.6	800 to 2,000
DRE-7	Drilling Rig Engines	LNC	10 to 20	4.4 to 11.5	1,400 to 3,400
DRE-8	Drilling Rig Engines	Low S Diesel	14	TBD	TBD
DRE-8	Drilling Rig Engines	NG	85 to 91	TBD	TBD
DRE-8	Drilling Rig Engines	Emulsified Diesel	20	5.9 to 15.3	4,500 to 11,600
DRE-9	Drilling Rig Engines	Tier 2 to Tier 4 Replacement	43 to 93	7.8 to 33.6	900 to 2,400
DRE-9	Drilling Rig Engines	Tier 3 to Tier 4 Replacement	43 to 89	4.7 to 20.1	900 to 2,000

1 For compressor engines and drilling rigs a range of NOx reductions is presented based on the range of engine sizes to which the control measure is applied. For drilling rigs there is also a wide variation in activity in different geographic regions.
2 For compressor engines and drilling rigs a range of cost-effectiveness values is presented based on the range of engine sizes to which the control measure is applied. For drilling rigs there is also a wide variation in activity in different geographic regions. If multiple engines are present on a single drilling rig, the measure is assumed to apply to all engines and the cost-effectiveness is estimated as the total cost of the measure for all engines on the rig, divided by the total potential NOx reductions.

CE-1 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines – Rich Burn

Control Measure Name: Nonselective Catalytic Reduction (NSCR)

Applicable Regulation: None for Engines less than 500 hp (Depends on State)

Application: This control measure applies to Rich-Burn engines > 50 hp

Pollutants: NOx, CO and HC

Control Efficiency: NOx: 90 to 98%, CO: 80%, HC: 50%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Capital and annual cost information was obtained from engine data gathered by Environ for the Northeast Texas Air Care pilot project. Cost information is summarized in the table below.

Table CE-1-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	13,500	6,000	$8,197
151 - 300	18,500	6,000	$9,011
301 - 500	20,500	7,000	$10,336
501 - 1000	30,500	8,000	$12,964
1001 - 1700	46,500	10,000	$17,568

Cost Effectiveness: $199/ton-NOx – $7,911/ton-NOx

Status: Demonstrated

Control Measure Description: This control method is applicable to all rich-burn engines, and is probably the most popular control method for these types of engines. Manufacturers generally do not offer lean-burn engines in sizes less than 300 hp so this technology would only apply to rich burn engines less than 300 hp. NSCR is essentially the same catalytic reduction technique used in automobile applications and is also referred to as a three-way catalyst system because the catalyst reactor simultaneously reduces NO_x, CO, and HC to water (H_2O), carbon dioxide (CO_2), and diatomic nitrogen (N_2). The chemical stoichiometry requires that O_2 concentration levels be kept at or below approximately 0.5 percent, and most NSCR systems require that the engine be operated at fuel-rich A/F's. As a result, CO and HC emissions typically increase, the brake-specific fuel consumption (BSFC) also increases due to the fuel-rich operation and the increased backpressure on the engine from the catalyst reactor.

Sustained NOx reductions are achieved with changes in ambient conditions and operating loads only with an automatic A/F control system, and a suitable A/F controller is not available for fuel-injected engines. Work by Environ in Northeast Texas has demonstrated NOx emission reduction efficiencies of 85 to 98 percent (Friesen, R., Russell, J., Lindhjem, C., Yarwood, G., 2006), greater than 80% for CO and greater than 50% VOC (CARB, 2001b). In tests run on seven different engines (each less than 500 hp and fueled with natural gas), an NSCR system (three-way catalyst and AFR controller) was found to have the greatest potential for reducing NOx emissions from this type of compressor engine. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr (20 to 110 ppmv). Numerous test reports support this NOx reduction efficiency range, but the corresponding CO emission levels range up to 37 g/hp-hr (4,500 ppmv) in some cases. Where controlled NO_x emission levels result in unacceptable CO emission rates, an oxidation catalyst may be required to reduce these emissions.

Other Impacts

The predominant catalyst material used in NSCR applications is a platinum-based metal catalyst. The spent catalyst material is not considered hazardous, and most catalyst vendors accept return of the material, often with a salvage value that can be credited toward purchase of replacement catalyst.

CE-2 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Air/Fuel Ratio Controllers (AFR)

Applicable Regulation:

Application: This control measure applies to Spark Ignition and Compression Ignition engines.

Pollutants: NOx

Control Efficiency: NOx: 10 to 40%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Capital and annual cost information was obtained from engine data gathered by Environ for the Northeast Texas Air Care pilot project. Cost information is summarized in the table below.

Table CE-2-1. Capital, O&M and annualized costs by engine horsepower. (Friesen, R., Russell, J., Lindhjem, C., Yarwood, G., 2006)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	4,200	N/A	$684
151 - 300	5,000	N/A	$814
301 - 500	5,000	N/A	$814
501 - 1000	5,300	N/A	$863
1001 - 1700	5,300	N/A	$863

Cost Effectiveness: $68/ton-NOx – $2,482/ton-NOx

Status: Demonstrated

Control Measure Description: This method has been used extensively on a wide variety of engines including SI and CI engines. Adjusting the A/F toward fuel-rich operation reduces the oxygen available to combine with nitrogen, thereby inhibiting NO_x formation. Figure CE2.1 shows the relationship between NOx formation to CO and VOCs. Stiochioimetry is achieved when the air/fuel ratio is such that all the fuel can be fully oxidized with no residual oxygen remaining. NOx formation is highest when the air/fuel ratio is slightly on the lean side of stiochiometric. At this point both CO and VOC are relatively low.

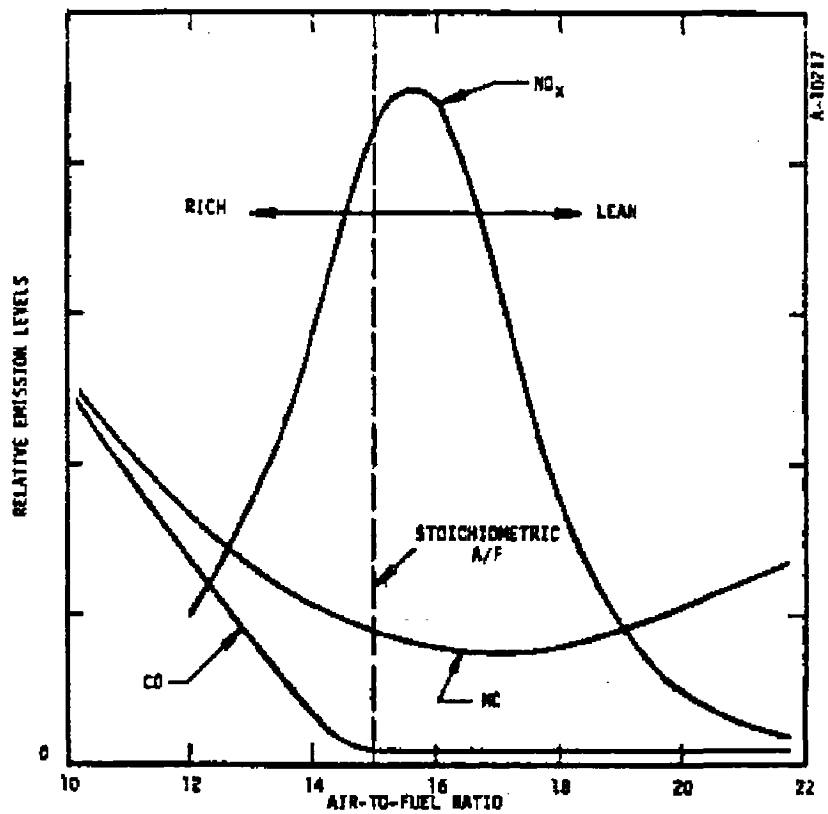


Figure CE2-1. The effect of air/fuel ratio on NOx, CO and VOC (HC).

The low-oxygen environment also contributes to incomplete combustion, which results in lower combustion temperatures and, therefore, lower NO_x formation rates. The incomplete combustion also increases CO emissions and, to a lesser extent, VOC (HC) emissions. Combustion efficiency is also reduced, which increases brake-specific fuel consumption (BSFC). Excessively rich A/F's may result in combustion instability and unacceptable increases in CO emissions.

The A/F can be adjusted on all new or existing rich-burn engines. Operating the engine on the lean side of the NOx formation peak is often preferred over operating rich because of increased fuel efficiencies associated with lean operation. Sustained NO_x reduction with changes in ambient conditions and engine load, however, is best accomplished with an automatic A/F control system.

The achievable NO_x emission reduction ranges from approximately 10 to 40 percent from uncontrolled levels. Based on an average uncontrolled NO_x emission level of 15.8 g/hp-hr the expected range of controlled NO_x emissions is from 9.5 to 14.0 g/hp-hr. Available data show that the achievable NO_x reduction using A/F varies for each engine model and even among engines of the same model, which suggests that engine design and manufacturing tolerances influence the effect of A/F on NO_x emission reductions.

Other Impacts

Another factor to consider in using A/F is that of engine load. At extremely low engine loads, such as those encountered in well-head natural gas may not be able to properly control the air-fuel ratio. In these situations other control technologies may be preferable to compressors operating in fields in which the field pressure is low, the A/F

Reference:

Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032

CE-3 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: **Ignition Timing Retard (ITR)**

Applicable Regulation:

Application: This control measure applies to Spark Ignition and Compression Ignition engines.

Pollutants: NOx

Control Efficiency: NOx: 15 to 30%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis:
Cost information is summarized in the table below.

Table CE-3-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	N/A	300	$300
151 - 300	N/A	450	$450
301 - 500	N/A	500	$500
501 - 1000	N/A	800	$800
1001 - 1700	N/A	900	$900

Cost Effectiveness: $42/ton-NOx – $1,210/ton-NOx

Status: Demonstrated

Control Measure Description: This technique can be used in all spark-ignited (SI) engines as well as compression-ignited engines. Retarding the ignition timing is based on retarding the timing to delay initiation of combustion to later in the power cycle. This method increases the volume of the combustion chamber and reduces the residence time of the combustion products thereby reducing the magnitude and duration of peak temperatures. This in turn has the potential for reduced NOx formation. The extent to which the ignition timing can be retarded to reduce NOx emissions varies for each engine, as ITR can increases exhaust temperatures, which may adversely impact exhaust valve life and turbocharger performance, and extreme levels of ITR may result in combustion instability and a loss of power. Brake-specific fuel consumption increases. While the maximum power output of the engine is reduced, this reduction is generally minor. In addition, emissions will increase. (CARB, 2001b)

Ignition timing can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished using an electronic ignition control system.

The achievable NOx emission reduction ranges from virtually no reduction to as high as 40 percent. For CI engines retarding the injection timing by about 4 degrees can reduce NOx by 15 to 30 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr, the expected range of controlled NOx emissions is from 9.5 to 15.8 g/hp-hr. Available data and information provided by engine manufacturers show that, like AFR, the achievable NOx reductions using ITR are engine-specific.

CE- 4 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: **Air Fuel Ratio (AFR) and Ignition Timing Retard (ITR)**

Applicable Regulation:

Application: This control measure applies to Spark Ignition and Compression Ignition engines.

Pollutants: NOx

Control Efficiency: NOx: 10 to 40%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost from Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032. Cost information is summarized in the table below.

Table CE-4-1. Capital, O&M and annualized costs by engine horsepower. (EPA, 1997)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	4,200	300	$984
151 - 300	5,000	450	$1,264
301 - 500	5,000	500	$1,314
501 - 1000	5,300	800	$1,663
1001 - 1500	5,300	900	$1,763

Cost Effectiveness: $105/ton-NOx – $3,571/ton-NOx

Status: Demonstrated

Control Measure Description: The combination of AF and IR can be used to reduce NO_x emissions. Available data and information from engine manufacturers suggest that the achievable NO_x emission reduction for the combination of control techniques is approximately the same as for AF alone (i.e., 10 to 40 percent) but offers some flexibility in achieving these reductions. Since parametric adjustments affect such operating characteristics as fuel consumption, response to load changes, and other emissions (especially CO), the combination of AF and IR offers the potential to reduce NO_x emissions while minimizing the impact on other operating parameters.

Other Reference:

Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032

CE- 5 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Prestratified Charge (PSC)

Applicable Regulation:

Application: This control measure converts rich-burn engines to lean-burn engines

Pollutants: NOx

Control Efficiency: NOx: 80%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-5-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	10,000	1,000	$2,627
151 - 300	23,000	1,500	$5,243
301 - 500	30,000	2,000	$6,882
501 - 1000	36,000	2,500	$8,359
1001 - 1500	47,000	3,000	$10,649

Cost information from Reference 3.

Cost Effectiveness: $136/ton-NOx – $2,979/ton-NOx

Status: Demonstrated

Control Measure Description: This control method converts rich-burn engines into lean burn engines. This add-on control technique facilitates combustion of a leaner air-fuel mixture. The major components of a PSC retrofit are the air injectors. The injectors pulse air into the intake manifold in such a fashion that layers or zones of air and the air/fuel mixture are introduced into the combustion chamber. The increased air content acts as a heat sink, reducing combustion temperatures, thereby reducing NO_x formation rates. Because this control technique is installed upstream of the combustion process, PSC is often used with engines fueled by sulfur-bearing gases or other gases (e.g., sewage or landfill gases) that may adversely affect some catalyst materials.

Prestratified charge applies only to four-cycle, carbureted engines. Pre-engineered, "off-the-shelf" kits are available for most new or existing candidate engines, regardless of age or size.

PSC has been installed on engines ranging in size up to approximately 2,000 hp. PSC can achieve greater than 80 percent control for NOx for power outputs up to about 70 to 80 percent of maximum.

Controlled NO_x emission levels of 2 g/hp-hr have been guaranteed, and available test data show numerous controlled levels of 1 to 2 g/hp-hr. The extent to which NO_x emissions can be reduced is determined by the extent to which the air content of the stratified charge can be increased without excessively compromising other operating parameters such as power output and CO and HC emissions.

Other Impacts: The leaner A/F effectively displaces a portion of the fuel with air, which may reduce power output from the engine. For naturally aspirated engines, the power reduction can be as high as 20 percent. This power reduction can be at least partially offset by modifying an existing turbocharger or installing a turbocharger on naturally aspirated engines. In general, CO and HC emission levels increase with PSC, but the degree of the increase is engine-specific. The effect on BSFC is a decrease for moderate controlled NO_x emission levels (4 to 7 g/hp-hr), but an increase for controlled NO_x emission levels of 2 g/hp-hr or less.

Other Reference:

Stationary Reciprocating Internal Combustion Engines, Alternative Control Techniques Document, EPA-453/R-93-032

CE- 6 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Low Emissions (L-E)

Applicable Regulation:

Application: This control measure applies to all Spark-Ignition Engines

Pollutants: NOx

Control Efficiency: NOx: 80%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-6-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)[1]

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	14,000	N/A	$2,278
151 - 300	24,000	N/A	$3,906
301 - 500	24,000	N/A	$3,906
501 - 1000	63,000	N/A	$10,253
1001 - 1500	148,000	N/A	$24,086

[1] Note: It is not likely that this measure will impact well-head compressor engines because this technology is generally applicable to engines larger than 500 hp and most, if not all well-head compressor engines are less than 500 hp.

Cost Effectiveness: $101/ton-NOx – $2,583/ton-NOx

Status: Demonstrated

Control Measure Description: This method has the potential to be used on all spark-ignition engines, but may not be offered by all manufacturers. The method is used to enhance the air/fuel ratio previously described. Basically, the leaner the mixture the lower the NOx emissions. However, to obtain substantial reductions, engine modifications are needed to assure that the fuel will ignite and to minimize fuel consumption penalties. Engine manufacturers have developed low-emission combustion designs (often referred to as torch ignition, or jet cell combustion) that operate at much leaner A/F's than do conventional designs. These designs incorporate improved swirl patterns to promote thorough air/fuel mixing and may include a precombustion chamber (PCC). A PCC is an antechamber that ignites a relatively fuel-rich mixture that propagates to the main combustion chamber. The high exit velocity from the PCC promotes mixing and complete

combustion of the lean A/F in the main chamber, effectively lowering combustion temperatures and, therefore, NO_x emission levels.
Low-emission combustion designs are available from engine manufacturers for most new SI engines, and retrofit kits are available for some existing engine models. For existing engines, the modifications required for retrofit are similar to a major engine overhaul, and include a turbocharger addition or upgrade and new intake manifolds, cylinder heads, pistons, and ignition system. The intake air and exhaust systems must also be modified or replaced due to the increased air flow requirements. The majority of engines that use this technology are in excess of 500 hp. Engine manufacturers do not offer lean burn engines in smaller size ranges (generally less than 300 hp).

Controlled NO_x emission levels reported by manufacturers for L-E are generally in the 2 g/hp-hr range, although lower levels may be quoted on a case-by-case basis. Emission test reports show controlled emission levels ranging from 1.0 to 2.0 g/hp-hr. Overall this technology has the potential to achieve 80 % reduction when combined with other NOx reduction techniques (i.e., precombustion chamber, ignition system improvement, turbo charging, air/fuel ratio controller) (CARB, 2001b). Information provided by manufacturers shows that, in general, BSFC decreases slightly for L-E compared to rich-burn designs, although in some engines the BSFC increases. An engine's response to increases in load is adversely affected by L-E, which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.

Other Impacts: Information provided by manufacturer's shows that, in general, BSFC decreases slightly for L-E compared to rich-burn designs, although in some engines the BSFC increases. An engine's response to increases in load is adversely affected by L-E, which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.

CE- 7 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: Selective Catalytic Reduction (SCR)

Applicable Regulation:

Application: This control measure applies to lean-burn engines.

Pollutants: NOx

Control Efficiency: NOx: 80%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-7-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)[1]

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	45,000	20,000	$27,324
151 - 300	45,000	26,000	$33,324
301 - 500	60,000	35,000	$44,765
501 - 1000	149,000	78,000	$102,249
1001 - 1700	185,000	117,000	$147,108

[1] Note: This measure will apply only to larger well-head compressor engines (>300 hp) since manufactures do not provide lean-burn engines in the less than 300 hp range.

Cost Effectiveness: $865/ton-NOx – $30,985/ton-NOx

Status: Demonstration Limited in Remote Applilcations

Control Measure Description: SCR is a proven technology for many combustion devices but only applicable as a NOx emissions reduction technique for lean-burn gas engines and diesel engines. Selective catalytic reduction is an add-on control technique that injects urea $(NH_2)_2CO$ or ammonia (NH_3) into the exhaust, which reacts with NO_x to form N_2 and H_2O in the catalyst reactor. The two primary catalyst formulations are base-metal (usually vanadium pentoxide) and zeolite. Spent catalysts containing vanadium pentoxide may be considered a hazardous material in some areas, requiring special disposal considerations. Zeolite catalyst formulations do not contain hazardous materials. The exhaust of lean-burn engines contains high levels of oxygen and relatively low levels of VOC and CO, which make the NSCR type catalyst ineffective at reducing NOx. SCR performs best when the oxygen level in the exhaust exceeds 2 to 3 percent.

Selective catalytic reduction applies to all lean-burn SI engines and can be retrofit to existing installations except where physical space constraints may exist. As is the case for NSCR catalysts, fuels other than pipeline-quality natural gas may contain contaminants that mask or poison the catalyst, which can render the catalyst ineffective in reducing NO_x emissions. Catalyst vendors typically guarantee a 90 percent NO_x reduction efficiency for natural gas-fired applications, with an ammonia slip level of 10 ppmv or less. One vendor offers a NO_x reduction guarantee of 95 percent for gas-fired installations. Based on an average uncontrolled NO_x emission level of 16.8 g/hp-hr, the expected controlled NO_x emission level is 1.7 g/hp-hr. Emission test data show NO_x reduction efficiencies of approximately 80 to 95 percent have been reported for existing installations (NESCAUM, 2000).

Other Impacts: Variable duty cycles result in exhaust temperatures that may fall outside the ideal catalyst temperature and result in variable NOx emissions that require correspondingly variable ammonia flow rates. Ammonia slip levels for manually adjusted ammonia injection control systems and ranged from 20 to 30 ppmv (EPA, 1997). Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases slightly due to the backpressure on the engine caused by the catalyst reactor. It should also be noted that some additional effort for engines using this technology and that are located in remote areas to be sure that ammonia slip does not occur.

CE- 8 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Compressor Engines

Control Measure Name: **Replacement of Older Engines with L-E Engine or Electric Motor**

Applicable Regulation:

Application: This control measure applies to all compressor engines.

Pollutants: NOx

Control Efficiency: NOx: 60 to 100%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table CE-8-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	14,000	unknown	$4,492
151 - 300	24,000	unknown	$8,023
301 - 500	40,000	unknown	$12,839
501 - 1000	90,000	unknown	$28,855

Cost Effectiveness: $103/ton-NOx – $4,743/ton-NOx

Status: Demonstrated

Control Measure Description: Another method of reducing NOx emissions is to replace the existing engine with an electric motor or a new engine designed to emit very low NOx emissions. However, in the case of compressor engines, it may also be necessary to make other modifications to accommodate the new type of engine. Significant emissions reductions on the order of 60% can be achieved depending on the age and type of engine that is being replaced. The Four Corners Air Quality Task Force has discussed the option of Industry Collaboration to replace older compressor engines, particularly those associated with natural gas compression that are less than 200 hp.

This would require companies to commit to ordering new engines over a prescribed time likely ahead of when the older units would have been replaced. Another approach is to replace the engine with an electric motor. An electric motor essentially eliminates NOx emissions associated with the removed engine although there may be minor increases in power plant emissions to supply the additional electricity for the electric motors. Limitations of this technique include the remote locations where many compressor engines are located and therefore the lack of electric power. The costs of engine replacement with an electric motor or new low emissions engine are highly variable, depending on the size of the engine, the cost of electricity, electric power availability, remaining useful life of the existing engine and other factors.

There are multiple variables to be considered in calculating the cost of electrification. For example, when looking at the impact on electrical loads from central station power plants, we would need to consider that many of the coal-fired power plants are undergoing Best Available Retrofit Technology (BART) analysis by their permitting agency, which could reduce SOx and NOx emissions per MWhr by large margins over the next several years. In addition, there are multiple factors to consider in converting an individual engine at a specific location including engine size, availability and distribution network for electricity, among others. The cost estimates presented in this measure provide an informational review of the likely costs of electrification, but do not make an exhaustive analysis or consider the impacts from increased electrical loads from central station power plants.

Another option under discussion by the Four Corners Air Quality Task Force (4CAQTF)is the optimization and or Centralization of compressor engines. This option would evaluate the deployment of engines used in various oil and gas operations with the appropriate horsepower rated to the need of the activity being conducted. Overall, the approach would theoretically reduce the cumulative horsepower deployed and thereby reduce the emissions. This may also be accomplished by using larger central compression in lieu of deploying numerous well head compressor engines. The attraction of this option is that many of the compressor engines were sized based on field conditions that existed at the time of purchase but field conditions have changed and many well-head compressor engines are operating at low load factors. Further, the use of larger centralized compressor engines increases the opportunity to use low emissions lean-burn engines. The difficulty with this option is that field conditions are continuously changing and optimizing field equipment would require numerous iterations as field conditions change. In some mature fields with low field pressures this measure may not be feasible as losses in pressure from a central compression station may cause the central compression design to be unable to provide sufficient compression.

The Four Corners Air Quality Task Force concluded that compressor optimization would not result in any measurable reduction in emissions. This conclusion for new engines was based on the follow assumptions:

1) Current lease agreements for production cannot be easily changed.
2) Engine emission factors do not change with load.
3) Emission factors on small engines are consistent with large engines (proposed NSPS will require this).

Other References: Determination of Reasonably Available Control Technology and Best Available Control Technology for Stationary Spark-Ignited Internal Combustion Engines, California Air Resources Board, November 2001.

DRE- 1 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Ignition Timing Retard (ITR)

Applicable Regulation:

Application: This control measure applies to Diesel Fired Drilling Rig Engines

Pollutants: NOx 15 to 30 %

Control Efficiency: NOx:

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. Injection Timing Retard Capital Costs = $12,200 for engines up to 1,000 hp and $16,300 for engines 1001 to 2500 hp, Annualized cost based on an average of 6,000 operating hours per year using the formula: $5,680 + ($6.9 x hp).

Table DRE-1-1. Capital, O&M and annualized costs by engine horsepower. (EPA, 1997)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	12,200	Incl	$6,600
151 - 300	12,200	Incl	$7,236
301 - 500	12,200	Incl	$8,443
501 - 1000	12,200	Incl	$10,858
1001 - 1500	16,300	Incl	$14,308

Cost Effectiveness: $1,034/ton-NOx – $2,243/ton-NOx

Status: Demonstrated

Control Measure Description: Injection timing retard in CI engines reduces NO_x emissions by the same principles as those for SI engines and is discussed in the discussion on compressor engines. Injection timing can be adjusted on all new or existing CI engines. Electronic injection control systems are used to maintain NO_x reductions. The control systems automatically adjust the timing for changes in ambient conditions and engine load.

Available data and information provided by engine manufacturers show that the achievable NO_x reductions using ITR is engine-specific but generally ranges from 20 to 30 percent. Based on an average uncontrolled NO_x emission level for diesel engines of 12.0 g/hp-hr, the expected range of controlled NO_x emissions is from 8.4 to 9.6 g/hp-hr. For dual-fuel engines, the average uncontrolled NO_x emission level is 8.5 g/hp-hr (620 ppmv) and the expected range of controlled NO_x emissions is from 6.0 to 6.8 g/hp-hr.

Other Impacts:

Data for ignition timing retard show no definite trend for CO and HC emissions for moderate levels of ignition retard in diesel engines and a slight increase in these emissions in dual-fuel engines. The BSFC increases with increasing levels of ITR for both diesel and dual-fuel engines. Excessive timing retard results in combustion instability and engine misfire (EPA, 1997).

DRE- 2 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: **Selective Catalytic Reduction (SCR)**

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: NOx

Control Efficiency: NOx: 80 to 95%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. SCR capital cost is estimated according to the formula $187,000 + ($98 x hp). Annual costs are based on average of 6,000 operating hours per year using the formula $113,000 + ($39.5 x hp).

Table DRE-2-1. Capital, O&M and annualized costs by engine horsepower. (EPA, 1997)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	196,800	Incl	$116,950
151 - 300	209,099	Incl	$121,907
301 - 500	226,249	Incl	$128,820
501 - 1000	260,549	Incl	$142,645
1001 - 1500	309,549	Incl	$162,395

Cost Effectiveness: $3,019/ton-NOx – $7,709/ton-NOx

Status: Demonstration Limited

Control Measure Description: Selective catalytic reduction applies to all CI engines and can be retrofit to existing installations except where physical space constraints may exist. This technology has been used in the last 15 years to significantly reduce NOx emissions. As discussed previously, the SCR system needs a chemical reagent or "reductant" to convert nitrogen oxides to molecular nitrogen and oxygen in the exhaust stream. The reductant is ammonia (NH_3), which is often generated from stored urea. This technology can reduce emissions from 65% to more than 90%. The reductant is added at a rate from an algorithm that estimates the amount of NOx present in the exhaust stream. The algorithm relates NOx emissions to engine operating conditions such as rpm and load. Both precious metal and base metal catalysts are used in SCR systems. Base metal catalysts (i.e., vanadium and titanium) are used for exhaust temperatures in the range of 450^0F to 800^0F. For higher temperatures (675^0F to

1100^{0}F) zeolite catalysts are often used. Precious metal catalysts may also be used at lower temperatures (350^{0}F to 550^{0}F).

Some base-metal catalysts utilize a guard bed upstream of the catalyst to catch heavy hydrocarbons that would otherwise deposit on the catalyst and mask the active surface. The SCR system is also often used in conjunction with a catalyzed diesel particulate filter which will remove particulate matter and some heavy hydrocarbons before they reach the SCR catalyst. In the past some catalysts were also susceptible to poisoning by sulfur (the maximum sulfur content of No. 2 diesel oil is 0.5 percent), but sulfur-resistant catalyst formulations are now available.

SCR is a California Air Resources Board-verified emission control technology for NOx reduction in off-road diesel engines (applicable to diesel-fired compressors and drill rig engines) (CARB, 2007b). Tests have already been conducted in Wyoming on SCR retrofits on typical drill rig engines, and these have reported up to 82% reduction in NOx emissions (ENSR, 2006). Zeolite catalyst vendors typically guarantee a NO_x reduction efficiency for CI engines of 90 percent or higher, with an ammonia slip of 10 ppmv or less. Base-metal catalyst vendors quote guarantees for CI engines of 80 to 90 percent NO_x reduction, with ammonia slip levels of 10 ppmv or less. Based on an average uncontrolled NO_x emission level of 12.0 g/hp-hr for diesel engines, the expected range of controlled NO_x emissions is from 1.2 to 2.4 g/hp-hr. For dual-fuel engines, the average uncontrolled NO_x emission level is 8.5 g/hp-hr and the expected range of controlled NO_x emissions is from 0.8 to 1.7 g/hp-hr. Emissions test data show NO_x reduction efficiencies of approximately 80 to 95 percent for existing installations

Other Impacts: With reduction efficiencies of 80 to 95 percent, ammonia slip levels range from 5 to 30 ppmv (ENSR, 2006). Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases approximately 1 to 2 percent due to the backpressure on the engine caused by the catalyst reactor.

Concern over ammonia emissions from SCR systems requires precise control of the ammonia injection rate. This is normally accomplished with precision controllers for the ammonia or urea injection. However increases in ammonia or urea injection rate can occur when the exhaust gas temperatures are too cold for the SCR reaction to proceed, and this may lead to ammonia slippage.

DRE- 3 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: **Exhaust Gas Recirculation (EGR)**

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: NOx

Control Efficiency: NOx: 40%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-3-1. Capital, O&M and annualized costs by engine horsepower.

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	10,200	5,000	$6,660
151 - 300	23,000	5,000	$8,743
301 - 500	40,849	5,000	$11,648
501 - 1000	51,049	5,000	$13,308
1001 - 1500	127,545	5,000	$25,757

Cost Effectiveness: $781/ton-NOx – $1,959/ton-NOx

Status: Demonstrated

Control Measure Description: This technology offers an effective means of reducing NOx emissions from diesel engines. Low pressure and high pressure systems are available. Low pressure systems are most commonly used for retrofit applications because engine modifications are not required. This method involves recirculating a portion of the engine exhaust back to the turbo-charger inlet or in the case of naturally aspirated engines, to the intake manifold. In most cases, an inter-cooler lowers the temperature of the exhaust gases being re-circulated. The cooler re-circulated gases have a higher heat capacity than air and contain less oxygen than air which lowers the combustion temperature in the engine by acting as both a heat sink and a diluent, and therefore reducing NOx formation. This technology is usually combined with diesel particulate filters to assure that large amounts of particulate matter are not re-circulated into the engine. NOx reductions of approximately 40% have been reported in mobile source applications (NESCAUM, 2003).

DRE- 4 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Crankcase Emission Controls (CEC)

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM

Control Efficiency: PM: 6 to 23%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-4-1. Capital, O&M and annualized costs by engine horsepower (Garett, J., 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	1,100	438	$617
151 - 300	1,100	438	$617
301 - 500	1,100	438	$617
501 - 1000	1,900	438	$747
1001 - 1500	3,500	438	$1,008

Status: Demonstrated

Control Measure Description: Crankcase emissions of particulate matter can be reduced by installing a multi-stage filter on the crankcase breather vent on turbocharged engines. The crankcase breather is often vented to the atmosphere resulting in large amounts of particulate matter being vented to the atmosphere. NESCAUM (NESCAUM, 2003) reported that emissions from the breather in mobile source applications can exceed 0.7 g/bhp-hr during idling conditions even on later model vehicles, which accounts for up to 25% of total tailpipe PM emissions. The multi-stage filters consist of a filter housing, pressure regulator, a pressure relief valve and an oil check valve. A crankcase filtration system can remove up to 90% of the crankcase blowby PM emissions, or from 6% to 23% of total exhaust PM emissions (Donaldson Corporation, 2003).

DRE- 5 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Diesel Particulate Filters (DPF)

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, CO, HC

Control Efficiency: PM: 85%
CO: 90%
HC: 90%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-5-1. Capital, O&M and annualized costs by engine horsepower (Garett, J., 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	8,000	5,000	$6,302
151 - 300	8,000	5,000	$6,302
301 - 500	8,000	5,000	$6,302
501 - 1000	16,000	5,000	$7,604
1001 - 1500	32,000	5,000	$10,208

Status: Demonstrated

Control Measure Description: Particulate matter (PM) from the exhaust of diesel engines can be reduced by diesel particulate filters (DPFs). This technology works both on stationary and mobile engines. Means are provided to either burn off or remove accumulated PM from the filters. Some systems burn off or oxidize the PM when exhaust temperatures are adequate. In some stationary applications, disposable filter systems are used. In recently designed systems, the filter must be removed or cleaned when backpressure limits are reached which may not be practical in all situations. Filter materials used include ceramic and silicon carbide materials, fiber wound cartridges, knitted silica fiber coils, ceramic foam, wire mesh, sintered metal substrates and temperature resistant paper in the case of disposable filters. Collection efficiencies range from 50% to over 90%. Several regeneration techniques are used to achieve efficient regeneration. These include catalyst-based regeneration using a catalyst applied to the surfaces of the filter to reduce the ignition temperation necessary to oxidize the particulate matter. Catalytic DPFs (also called CDPFs) are the most effective at oxidizing PM and are the most common type of DPF used in mobile source applications. Some work has begun to make DPFs compatible with off-road diesel engines, but to date suitable DPFs have not been designed for all categories of off-road engines. Sulfur in the diesel fuel affects the reliability, durability and emissions performance of catalyst-based diesel particulate filters in off-road applications in which high sulfur content fuel is encountered. However, with new EPA-mandated diesel sulfur level regulations expected to come into effect by 2010 this issue should be resolved by the 2018 scenario year considered here. When the duty cycle of the engine prohibits a regeneration temperature from being reached in the engine, catalytic regeneration is not possible. Other techniques used include an on-board fuel burner or electric heaters to provide sufficient exhaust temperatures to ignite accumulated particulate matter and regenerate the filter.

The type of DPF used depends on the fuel sulfur content, filter system, operating conditions and the control level desired. It should be noted that an additional benefit of the DPF is the reduction that is achieved in reducing toxic hydrocarbon emissions.

DRE- 6 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Diesel Oxidation Catalyst (DOC)

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, CO, HC

Control Efficiency: PM: 25%
CO: 90%
HC: 90%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. Assume that DOC costs $2500 for equipment in 150-300 HP range, or average horsepower 238hp. Therefore the average DOC cost is $10.4/hp.

Table DRE-6-1. Capital, O&M and annualized costs by engine horsepower (Garett, J., 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	1,040	0	$169
151 - 300	2,345	0	$382
301 - 500	4,165	0	$678
501 - 1000	7,805	0	$1,270
1001 - 1500	13,005	0	$2,117

Status: Demonstrated

Control Measure Description: Diesel oxidation catalysts are used to reduce PM, CO and HC. PM emissions are reduced by the chemical transformation of their soluble organic fraction to carbon dioxide and water. Different catalytic formulations can be used to target different pollutants more aggressively than others. The catalysts consist of steel housings that contain metal or ceramic structure which acts as a catalyst substrate. Catalyst materials include platinum, rhodium and palladium. Reductions in excess of 50% are readily achieved and in some cases approach 70% for some compounds. DOCs are virtually maintenance free but periodic inspections are advisable to assure that cell plugging is not occurring. As with DPFs, DOCs are also affected by sulfur. The sulfur content of the diesel fuel is therefore important in applying this technology. With sulfur, the catalyst can also oxidize the sulfur dioxide to form sulfates which add to the total particulate matter emissions. However, catalyst formulations have been developed to minimize the oxidation of sulfur dioxide. Overall, the lower the sulfur content of the fuel, the more opportunity to maximize the effectiveness of the technology.

DRE- 7 - CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: **Lean NOx Catalyst (LNC)**

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: NOx

Control Efficiency: NOx: 10 to 20 %

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-7-1. Capital, O&M and annualized costs by engine horsepower. (Swenson, T., Cleaire, 2007)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	17,225	5000	$7,543
151 - 375	17,225	5000	$7,543
375 - 450	19,590	5000	$7,928
450 - 600	24,496	5000	$8,726
601-1500	N/A	N/A	N/A

Cost Effectiveness: $1,366/ton-NOx – $3,401/ton-NOx

Status: Demonstrated

Control Measure Description: In a Lean NOx catalyst, NOx is converted to N_2 using a small amount of reductant (diesel fuel or other hydrocarbon reductant) injected into the exhaust. Other systems operate passively at reduced NOx conversion rates. In passive systems, catalyst substrates are often made of zeolite which is a porous material and can provide microscopic sites that are fuel/hydrocarbon rich where reduction reactions can take place. When using reductants, a HC to NOx ratio of up to 6:1 is needed to achieve optimal NOx reductions. NOx conversion rates are typically around 10 – 20 %. However, the fuel penalty can be about 3%. Two types of lean NOx catalysts are available: a low temperature catalyst based on platinum and a high temperature catalyst utilizing base metals such as copper. Each type of catalyst is capable of converting NOx over a narrow temperature range and can be combined to broaden the temperature range over which they convert NOx.

DRE- 8- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Fuel Switching

Applicable Regulation:

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, CO, NOx

Control Efficiency: PM: 14% (Low sulfur diesel fuel)
NOx: 85 to 91% (Natural gas)
PM: 50 to 80% (Natural gas)
NOx: 20 % (Diesel Emulsions)
PM: 17% (Diesel Emulsions)
CO: 13% (Diesel Emulsions)
HC: 30 to 99% Increase (Diesel Emulsions)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-8-1. Capital, O&M and annualized costs by engine horsepower.

	Horse Power Range	Capital Cost	O&M	Annualized Cost
Low Sulfur Diesel	50 - 150	N/A	N/A	$0
	151 - 300	N/A	N/A	$0
	301 - 500	N/A	N/A	$0
	501 - 1000	N/A	N/A	$0
	1001 - 1500	N/A	N/A	$0
	Horse Power Range	**Capital Cost**	**O&M**	**Annualized Cost**
NG	50 - 150	9500	0	$1,465
	151 - 300	9500	0	$1,465
	301 - 500	9500	0	$1,465
	501 - 1000	N/A	N/A	N/A
	1001 - 1500	N/A	N/A	N/A
	Horse Power Range	**Capital Cost**	**O&M**	**Annualized Cost**
Emulsion	50 - 150	TBD	N/A	TBD
	151 - 300	TBD	N/A	TBD
	301 - 500	TBD	N/A	TBD
	501 - 1000	TBD	N/A	TBD
	1001 - 1500	TBD	N/A	TBD

Cost Effectiveness: Low-sulfur diesel: TBD
NG: TBD
Emulsion: $4,509/ton-NOx – $11,627/ton-NOx

Status: Demonstrated

Control Measure Description:

Low Sulfur Diesel - Switching to Low Sulfur fuel can reduce engine particulate emissions from drill rigs. A manufacturers study conducted by the manufacturers (MECA, 2002) switching from 368 ppm sulfur fuel to 54 ppm sulfur fuel reduced engine PM emissions from 0.073 g/bhp-hr to 0.63 g/bhp-hr, or about 14% as measured over the Federal Test Procedure. As noted above, the US EPA is mandating the use of low-sulfur diesel fuel in on- and off-road CI engine applications and this mandate will be in effect by the 2018 scenario year considered in this analysis. Thus switching to low-sulfur diesel should be considered in conjunction with other control measures.

Natural Gas – Some producers have opted to install natural gas-fired engines when replacing existing drill rigs (ENSR, 2006). This option has some limitations because a natural gas fuel source must be readily available at the location of the drilling operations. If a natural gas supply is available in close proximity, there may be a cost savings in fuel, however, if installation of piping to transport the natural gas is required, this option may be significantly more expensive than diesel fuel. Initial estimates for NOx emissions reductions are 85% for Tier 1 engines and 91% for Tier 9 engines. In addition, natural gas engines will emit significantly less particulate matter with reductions of 50%-80% in PM emissions.

Diesel Fuel Emulsions – Diesel fuel emulsions use surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture which ensure that the water does not contact metal engine parts. This technology reduces peak engine combustion temperatures and increases fuel atomization and combustion efficiency. Depending on the size of the engine NOx reductions of approximately 20% can be achieved. In addition, particulate matter reductions of 17% and CO reductions of 13% have been reported (Four Corners Air Quality Task Force, 2007). However, HC emissions can significantly increase (30 to 99 %). This technology can be used in conjunction with a diesel oxidation catalyst to reduce the HC and CO emissions and further reduce PM emissions. Engines using this technology typically experience a 15% increase in fuel consumption and a 20% power loss at maximum engine hp. Fuel mixing and a storage unit would also be required.

Other Impacts: Diesel fuel emulsions have been verified by the California Air Resources Board (CARB) and EPA for use in warm-weather climates, but not yet verified for use in cold-weather climates. In cold weather, emulsions may have operational difficulties due to ice formation in the emulsion. Fuel emulsion manufacturers are currently working to develop a cold-weather blend of emulsified diesel fuel. In addition, some tests have shown engine wear and corrosion after long-duration use of emulsified fuels, but given the fairly rapid turnover of diesel engines in drill rigs this is not expected to be a significant issue.

DRE- 9- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Drilling Rig Engines

Control Measure Name: Repowering/Replacing Engines

Applicable Regulation: By 2015 all large (> 750 hp) stationary and nonroad diesel engine must meet federal EPA Tier 4 standards.

Application: This control measure applies to Diesel-fired Drilling Rig Engines

Pollutants: PM, NOx, HC

Control Efficiency: NOx+NMHC: 87% (Tier 2 to Tier 4)
PM: 85% (Tier 2 to Tier 4)
NOx+NMHC: 85 % (Tier 3 to Tier 4)
PM: 85% (Tier 3 to Tier 4)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below.

Table DRE-9-1. Capital, O&M and annualized costs by engine horsepower.

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	12500	0	$1,953
151 - 300	27560	0	$4,404
301 - 500	48560	0	$7,822
501 - 1000	90560	0	$14,657
1001 - 1500	150560	0	$24,422

Cost Effectiveness: Tier 2 to Tier 4: $933/ton-NOx – $2,383/ton-NOx
Tier 3 to Tier 4: $935/ton-NOx – $2,034/ton-NOx

Status: Not yet available (expected in 2011 for < 750 HP engines, 2014 for > 750 HP engines)

Control Measure Description:

Repowering/Replacing Engine –This measure refers to replacing a drilling rig with a new rig or replacing the engines of a drilling rig with new engines that will meet the Tier 4 nonroad engine standard at the time of purchase. All new stationary and nonroad diesel engines that are manufactured and purchased new in 2015 must meet the Tier 4 nonroad standards which represent significantly tighter emissions restrictions than Tier 2 or 3 standards. The NOx + NMHC emissions standards for Tier 4 engines represent a 87% reduction from Tier 2 standards and the PM emissions standards for Tier 4 engines represent a 85% reduction from Tier 2 standards. For large engines > 750 HP, there is no Tier 3 standard and so these engines will be Tier 2 engines at the time that engine replacement becomes viable. Given the expected lifetime of a drilling rig of 10 years, it is expected that in 2018 most of the drilling rig engines will be Tier 2 (for large engines) and Tier 3 (for smaller engines). It is expected that Tier 4 engines would achieve these emissions reductions through better engine design and through the use of after-treatment control technology, thus this technology should not be considered separately with these engines.

EAP- 1- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Glycol Dehydration Units

Control Measure Name: Optimize Glycol Circulation Rate, Electric Pump Installation, Flash Tank Separator

Applicable Regulation:

Application: This control measure applies to well head glycol dehydration units

Pollutants: VOC

Control Efficiency: VOC: 33 to 67% (Optimize glycol circulation rate)
VOC: 67% (Electric pump installation)
VOC: 10 to 40% (Flash tank separator)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

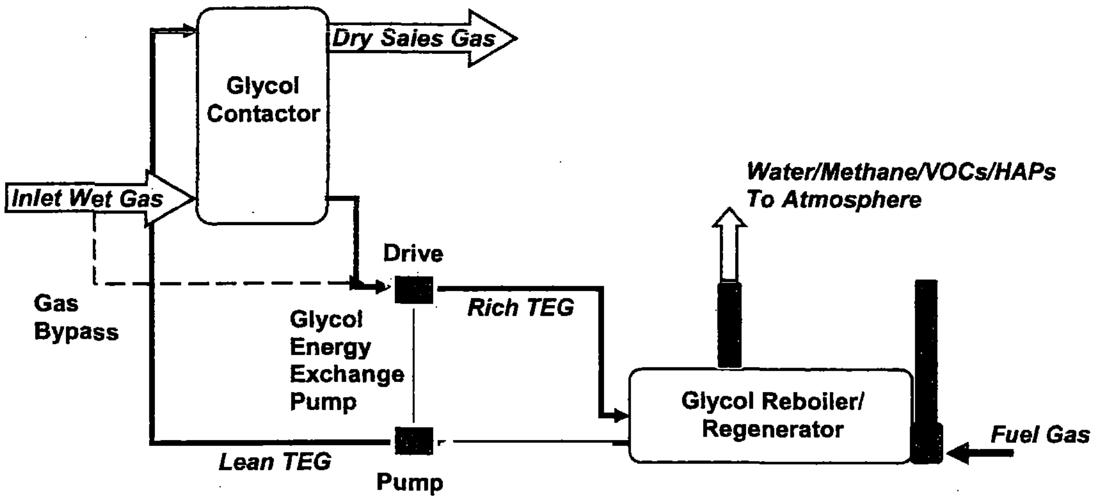
Cost Basis: Cost information is summarized in the table below. It was assumed that there would be no additional cost to operators for reducing the circulation rate (EPA, 2003c). For the electric pump installation, costs were based on a 3.0 hp electric pump, and the O&M costs for this pump include electricity cost ($200/yr), electric pump maintenance ($200/yr) and gas-assisted pump maintenance ($400/yr) (EPA, 2004a). Installation for different circulation rates was based on installing a flash tank separator on a dehydrator with an energy-exchange pump (EPA, 2003c).

Table EAP-1-1. Capital, O&M and annualized costs.

Technology	Size	Capital Cost	O&M	Annualized Cost
Optimize Circulation	NA	NA	NA	$0
Electric Pump	NA	1,853	2,176	$2,478
Flash Tank	30 gal/hr	5,160	Negligible	$840
Flash Tank	150 gal/hr	5,560	Negligible	$905
Flash Tank	300 gal/hr	7,160	Negligible	$1,165
Flash Tank	450 gal/hr	13,920	Negligible	$2,265

Status: Demonstrated

Control Measure Description: Produced natural gas usually contains saturated water which can condense and/or freeze in gathering, transmission and distribution piping causing plugging, pressure surges and corrosion. Dehydrators are used to remove water in the produced natural gas. This is done by passing the natural gas through a dewatering agent such as triethylene glycol (TEG), diethylene glycol (DEG) or propylene carbonate. The most common form used is the TEG, which absorbs water along with methane, VOCs and HAPs. The absorbed water and Hydrocarbons are then boiled off in a reboiler/regenerator and vented to the atmosphere. A diagram of the dehydration flow process diagram is shown in Figure EAP.1.



Source: Presentation on Minimizing Methane Emissions from Glycol Dehydrators, Offshore Technology Workshop, June 6, 2004

Figure EAP-1 Glycol dehydrator process diagram.

From the diagram, you can see that VOCs are vented to the atmosphere from the glycol Reboiler/Regenerator. As production rates decrease over time, glycol unit designed for the original production rates tend to over circulate causing emission increases without significant reduction in gas moisture content. Emission rates depend on the gas flow rate, the inlet and outlet water content, the glycol-to-water ratio, the percent over circulation and the methane entrainment rate. Also VOCs are emitted from the pneumatic control devices. Using a calculation from the EPA Natural Gas Star Lessons Learned (EPA, 2003a) that a 1 MMcfd TEG Glycol Dehydrator will emit 69 Mcf per year and the pneumatic control system will emit 504 Mcf per year (assuming 4 bleeding controllers). On average 600 Mcf of Methane is emitted from each glycol dehydrator per year. One producer has provided emissions estimates for glycol dehydrators at 97.93 lb/mmscf based on average operations using the Florida GlyCalc models. Estimates for dehydrator burners using AP-42 factors of 8.0 lb/mmscf. Several options are available to reduce or remove emissions of VOCs from dehydration operations. In addition to reducing emissions these options will result in methane savings, potentially lower operating costs and short-term paybacks in the control technology costs.

Optimize Glycol Circulation Rate

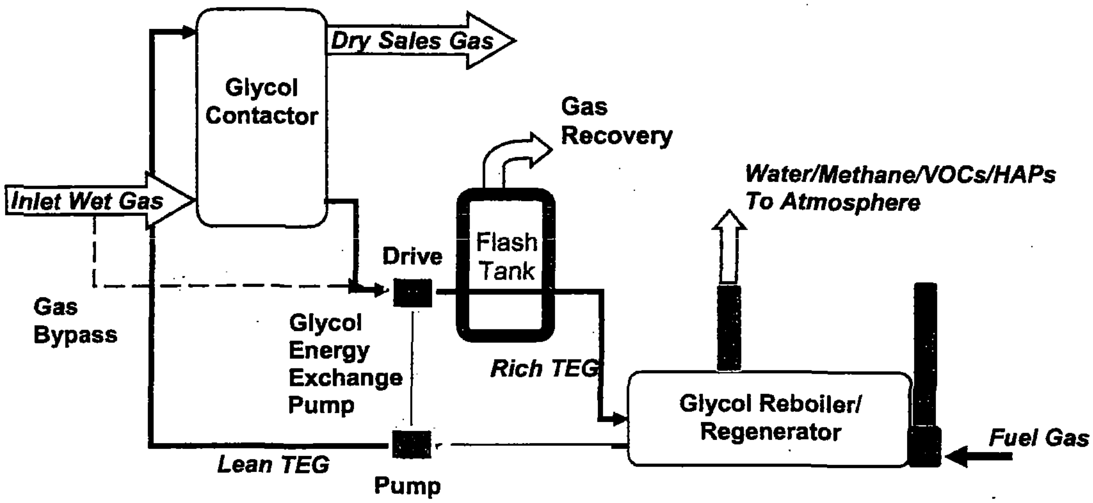
Natural Gas Star partners have found that dehydrator systems often circulate the TEG at rates two or more times greater than necessary (EPA, 2003c). Operators can reduce the TEG recirculation rate and significantly reduce emissions. TEG recirculation rates ranging from 45 to 2250 gal/hr that are reduced from 30 to 750 gal/hr show annual Methane reductions of 400 to 40,000 Mcf. In a glycol dehydrator, the water removal rate is a function of the gas flow rate and the amount of water to be removed from the gas stream. The TEG to water ratio (how many gallons of TEG is required to absorb 1 pound of water) varies between 2 and 5 gallons of TEG per pound of water. Accepted rule-of-thumb rate is 3 gallons of TEG per pound of water.

Electric Pump Installation

To circulate the TEG through the dehydrator, circulation pumps are used. The most common pump used in remote areas is a gas-assisted pump. These are basically pneumatic gas driven pumps designed to take advantage of the energy of high-pressure natural gas entrained in the rich (wet) TEG leaving the gas contactor. Additional high-pressure wet production gas is necessary for mechanical advantage, and therefore more methane rich gas is carried to the TEG regenerator where it is vented with the water boiled off the rich TEG. The mechanical design of these pumps places, wet, high pressure TEG opposed to dry, low pressure TEG,. Separated only by rubber seals. Worn seals result in contamination of the lean (dry) TEG making it less efficient in dehydrating the gas, requiring high glycol circulation rates. Typical emissions are about 1,000 cubic (Mcf) for each million cubic feet (MMcf) of gas treated. Replacing gas-assisted pumps with electric pumps increases system efficiency and significantly reduces emissions. For example, a 10 MMcf per day dehydrator could save up to 3,000 Mcf of gas per year (EPA, 2004a). As a rule-of-thumb, for every volume of gas absorbed in the rich TEG leaving the contactor, two more volumes of gas must be added from wet feed gas to supply enough power in the driver for the lean TEG pump. Therefore, using either a piston or gear-type energy exchange pump triples the amount of gas entrained with the TEG and vented to the atmosphere when no Flash Tank Separator is used.

Flash Tank Separator

Most production and processing dehydrators send the glycol/gas mixture from the TEG circulation pump directly to the regenerator where all the methane and VOCs entrained with the rich TEG vent to the atmosphere. Some installations use Flash tank separators to separate the gas and liquid at low system pressure without added heat. At this low pressure the gas is rich in methane and lighter VOCs but water remains in solution with the TEG. The wet TEG largely depleted of methane and VOCs then flows to the glycol reboiler/regenerator where it is heated to boil off the adsorbed water and any remaining methane or VOCs. A system diagram is shown in Figure EAP.2.



Source: Presentation on Minimizing Methane Emissions from Glycol Dehydrators, Offshore Technology Workshop, June 6, 2004

Figure EAP-2. Glycol dehydration unit with flash tank separator.

One industry study found that flash tank separators were not used in 85 percent of dehydration units processing less than one MMscfd of gas, 60 percent of units processing one to five MMscfd of gas, and 30 to 35 percent of units processing over five MMscfd of gas (EPA, 2003c). The flash tank separates approximately 90 percent of the methane and 10 to 40 percent of the VOCs entrained in the TEG.

EAP- 2- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Pneumatic Controls

Control Measure Name: **Instrument Air Controllers, Non-bleed devices**

Applicable Regulation:

Application: This control measure applies to well head pneumatic controls

Pollutants: VOC

Control Efficiency: VOC: 98%

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. The costs for air controllers are based on a medium-sized installation (125 cfm compressor, 400 gallon tank, 60 cfm air dryer). The O&M costs for this technology include compressor service ($1200), air dryer replacement ($2,000) and electric service ($0.075/kWh) (EPA, 2004e). Cost information for non-bleed devices is based on a BP America program to reduce greenhouse gas emissions by retrofitting 4860 controllers at 1300 wells at a cost of $400 per controller (Smith, G.R., 2000).

Table EAP-2-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
Instrument Air	NA	45750	16,340	$23,786
Non-bleed	NA	1,495	Negligible	$243

Status: Demonstrated

Control Measure Description: A variety of process control devices are used by the natural gas industry to operate valves that regulate pressure, flow, temperature and liquid levels. These instruments can be classified as pneumatic, electrical or mechanical devices. Most of the instruments used in production, however, are pneumatic devices, which make use of the available high-pressure natural gas onsite. Further, many of these sites do not have available electricity. These devices control and monitor gas and liquid flows, temperature in dehydrator regenerators and pressure in flash tanks. Most of the pneumatic control systems are operated at 20 to 30 psi and consist of a network of distribution tubing to supply all of the control instruments. Natural gas is also used for some utility services such as small pneumatic pumps, compressor motor starters and isolation shutoff valves.

As part of normal operation, natural gas powered pneumatic control devices release or bleed gas to the atmosphere and consequently, are a major source of methane emissions from the natural gas industry. According to BP (Frederick, J., Phillips, M., Smith, G.R., Henderson, C., Carlisle, B., 2000), these controllers were venting an average of 840 scf per day per controller. For BP operations, this amounted to 1.5 bcf of field gas per year.

Instrument Air Controllers

Significant emissions reductions can be achieved by converting natural gas-powered control systems to compressed instrument air systems. These systems substitute compressed air for pressurized natural gas, eliminating methane emissions and depending on the natural gas content VOC emissions. The benefits of this conversion is that existing pneumatic gas supply piping, control instruments and valve actuators can be reused when converting the compressed air systems. The downside of this type of system is the need for a compressor and therefore an electrical supply onsite. However, for those sites without electricity, emissions reductions can be achieved by replacing high-bleed devices with low bleed devices, retrofitting high-bleed devices and improving maintenance practices.

Replace Continuous-Bleed Controllers with Non-bleed Devices

In some cases, it is not practical to install instrument air controllers due to lack of onsite electrical power or other reasons. Replacing the continuous bleed controllers with non-bleed displacement-type controllers was demonstrated by BP to reduce the average venting to 12 scf of field gas per day, a reduction of over 98 percent from continuous-bleed devices. BP reported that they replaced about 70 percent of the continuous-bleed controllers in 1999 and the remainder in 2000. However there were, site-specific factors that prevented them from replacing all 4,900 controllers with the single-snap acting model that had been selected. These included controllers at wells producing dirty fluids that tended to foul the controller orifices or wells producing crude too light to trigger the controller's liquid dump valve. In some cases alternative non-bleed devices were selected and in other cases they were able to modify the controller or use retrofit kits to reduce bleed rates on existing controllers.

EAP- 3- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Completion Venting and Flaring

Control Measure Name: **Flaring and Green Completion**

Applicable Regulation:

Application: This control measure applies to well head pneumatic controls

Pollutants: VOC

Control Efficiency: VOC: 62 to 98% (Flaring)
VOC: 70% (Green Completions)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. Note that this measure is not intended to be an installation option, but is included for reducing venting where flares are currently installed. The cost information is based on portable separators, sand traps and tanks that can recover an average of 2.5 barrels per well (EPA, 2004d).

Table EAP-3-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
Flaring	NA	N/A	N/A	N/A
Green Completion	NA	180,000	1,000	$30,294

Status: Demonstrated

Control Measure Description: The last step in a well becoming a "producing well" is cleaning the well bore and the reservoir immediately surrounding the well. This "well completion" traditionally involves producing the well to open pits or tankage where sand, cuttings, and the reservoir fluids are collected for disposal and the produced natural gas is vented to the atmosphere. Venting the gas releases methane and depending on the composition of the gas other hydrocarbons and HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compound such as hydrogen sulfide (H_2S). In the New Mexico portion of the San Juan Basin, there are at least 375 gas wells, from at least five different producing formations, that contain H_2S (Hewitt, J., 2005). Wellhead natural gas can range from 70 to 90 percent methane (EPA, 2004b). Several steps can reduce emissions from well completions.

Flaring

Flaring is used to convert natural gas to less hazardous and less reactive compounds. Flaring in the field has been shown to have lower efficiencies than typical flares used in refineries and other processes. While not many studies have been conducted, flares used in the field have shown to have efficiencies from 62% to 84% (Strosher, M., 1996). In addition, hydrocarbon byproducts may include VOCs considered Hazardous Air Pollutants (HAPs). Flares operated during well completion activities are required to handle large volumes of gas. The state of Wyoming has estimated the VOCs produced during a typical well completion. A single well completion event has been estimated to average 8 days and emit 115 tons of VOCs (assuming 100% venting). It is also estimated that 29 tons VOCs are released when flaring based on 50% of the gas being vented and a flare operating at an efficiency of 50% (Russell, J., Pollack A., 2006).

The results from one study conducted by the International Flare Consortium (IFC), showed that when the flares were operated under conditions representative of good industrial practice, the combustion efficiencies were >98% (McDaniel M., 1983). Exceptions occurred when intentionally excessive steam quenched the flame or when low Btu gases were intentionally flared at high velocity.

Green Completions

Green completions recover natural gas and condensate produced during well completions by using portable equipment that may include additional tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The gas is directed through permanent dehydrators and meters to sales lines thereby reducing venting and flaring emissions. One EPA Gas Star Partner reported 70% reductions in the gas formerly vented to the atmosphere.

EAP- 4- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Tanks

Control Measure Name: Vapor Recovery Units, Convert Water Tank Blanket

Applicable Regulation:

Application: This control measure applies to well head fugitive emissions

Pollutants: VOC

Control Efficiency: VOC: 95% (Vapor Recovery Unit)
VOC: Convert Water Tank Blanket (To be determined)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. The costs for a vapor recovery unit were estimated assuming that installations costs would be 75% of the unit cost and would recover 95% of the gas (EPA, 2003b). Costs for the water tank blanket were based on blanketing a 4,000 barrel water tank that is emptied twice per week. Capital cost was assumed to be in the middle of the $1,000 to $10,000 range (EPA, 2004c).

Table EAP-4-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
VRU	25 Mcfd	26,470	5,259	$9,567
VRU	50 Mcfd	34,125	6,000	$11,554
VRU	100 Mcfd	41,125	7,200	$13,893
VRU	200 Mcfd	55,125	8,400	$17,371
VRU	500 Mcfd	77,000	12,000	$24,531
Water Blanket	NA	5,000	100	$914

Status: Demonstrated

Control Measure Description: Storage are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites. During storage, light hydrocarbons dissolved in the crude oil such as volatile organic compounds vaporize or "flash out" and collect in the space between the liquid and the fixed roof of the tank. As the level of the tank fluctuates, these vapors are often vented to the atmosphere. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons and water are removed through a series of high pressure and low-pressure separators. The crude oil is then injected into a storage tank to await sale and transportation offsite. Losses of lighter hydrocarbons can occur by 1) flashing losses when the separator or heater-treater, operating at 35 psi, dumps oil into the storage tank at atmospheric pressure, 2) working losses released from the changing fluid levels and agitation of tank contents associated with the circulation of fresh oil through the storage tanks and 3) standing losses from daily and seasonal temperature changes. Vapor recovery units are installed on many of these tanks.

Vapor Recovery Units

Vapor recovery units (VRUs) can capture over 95 percent of the hydrocarbon emissions that accumulate in storage tanks. VRU systems typically draw hydrocarbon vapors out of the storage tank under low pressure and pipe the vapors to a separator to collect any liquids. The vapors are then routed through a compressor that provides low-pressure suction for the VRU system. VRUs are equipped with a control pilot to shut down the compressor and permit the back flow of vapors to the tank. The vapors are then metered and removed from the VRU system for pipeline sale or onsite fuel supply.

Convert Water Tank Blanket

Produced water is normally transferred to the fixed roof storage tank where the drop in pressure results in release of gases. This gas can also mix with the air in the tank to form an explosive mixture. Under this option, fixed rood tanks would be modified or new tanks would be installed to provide the capability of placing an inert gas blanket of the tanks to minimize vapor losses. This is accomplished by filling the space above the condensate/crude oil mixture to minimize VOCs from being emitted to the atmosphere.

EAP- 4- CONTROL TECHNOLOGY WHITE PAPER

Source Category: Tanks

Control Measure Name: **Vapor Recovery Units, Convert Water Tank Blanket**

Applicable Regulation:

Application: This control measure applies to well head fugitive emissions

Pollutants: VOC

Control Efficiency: VOC: 95% (Vapor Recovery Unit)
VOC: Convert Water Tank Blanket (To be determined)

Equipment Life: 10 years

Penetration: (Range to be determined)

Emissions Reduction: (state-level 2018 emissions to be added)

Cost Basis: Cost information is summarized in the table below. The costs for a vapor recovery unit were estimated assuming that installations costs would be 75% of the unit cost and would recover 95% of the gas (EPA, 2003b). Costs for the water tank blanket were based on blanketing a 4,000 barrel water tank that is emptied twice per week. Capital cost was assumed to be in the middle of the $1,000 to $10,000 range (EPA, 2004c).

Table EAP-4-1. Capital, O&M and annualized costs.

Technology	Size Range	Capital Cost	O&M	Annualized Cost
VRU	25 Mcfd	26,470	5,259	$9,567
VRU	50 Mcfd	34,125	6,000	$11,554
VRU	100 Mcfd	41,125	7,200	$13,893
VRU	200 Mcfd	55,125	8,400	$17,371
VRU	500 Mcfd	77,000	12,000	$24,531
Water Blanket	NA	5,000	100	$914

Status: Demonstrated

Control Measure Description: Storage are used to hold oil for brief periods of time in order to stabilize flow between production wells and pipeline or trucking transportation sites. During storage, light hydrocarbons dissolved in the crude oil such as volatile organic compounds vaporize or "flash out" and collect in the space between the liquid and the fixed roof of the tank. As the level of the tank fluctuates, these vapors are often vented to the atmosphere. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons and water are removed through a series of high pressure and low-pressure separators. The crude oil is then injected into a storage tank to await sale and transportation offsite. Losses of lighter hydrocarbons can occur by 1) flashing losses when the separator or heater-treater, operating at 35 psi, dumps oil into the storage tank at atmospheric pressure, 2) working losses released from the changing fluid levels and agitation of tank contents associated with the circulation of fresh oil through the storage tanks and 3) standing losses from daily and seasonal temperature changes. Vapor recovery units are installed on many of these tanks.

Vapor Recovery Units

Vapor recovery units (VRUs) can capture over 95 percent of the hydrocarbon emissions that accumulate in storage tanks. VRU systems typically draw hydrocarbon vapors out of the storage tank under low pressure and pipe the vapors to a separator to collect any liquids. The vapors are then routed through a compressor that provides low-pressure suction for the VRU system. VRUs are equipped with a control pilot to shut down the compressor and permit the back flow of vapors to the tank. The vapors are then metered and removed from the VRU system for pipeline sale or onsite fuel supply.

Convert Water Tank Blanket

Produced water is normally transferred to the fixed roof storage tank where the drop in pressure results in release of gases. This gas can also mix with the air in the tank to form an explosive mixture. Under this option, fixed rood tanks would be modified or new tanks would be installed to provide the capability of placing an inert gas blanket of the tanks to minimize vapor losses. This is accomplished by filling the space above the condensate/crude oil mixture to minimize VOCs from being emitted to the atmosphere.

5. 2018 EMISSIONS FORECASTS

PROJECTION METHODOLOGY

Two methods were used to estimate 2018 county level oil and gas emissions. The first and by far the dominant method was to develop growth factors to project from the 2005 oil and gas county-level emissions described in the previous task. A second method was then necessary to estimate emissions in the counties that had no 2005 oil and gas emissions but are anticipated to see oil and gas development by 2018.

The growth factors used to project county level emissions from 2005 to 2018 were derived from projections of future oil and gas production reported by several sources. The preferred source of production projections was the Federal Bureau of Land Management (BLM), which prepares Resource Management Plans (RMPs) for the lands and mineral resources under its stewardship, and often oversees the preparation of Environmental Impact Statements (EIS). RMPs and EIS's for oil and gas production areas typically include an estimate of reasonably foreseeable oil and gas development (RFD). This was the same method employed in the previous Phase I analysis, which made use of the RMPs available at that time. In the current analysis the RMPs previously used were reviewed to determine if any revisions or updates had been made. Frequently, RMPs are modified by the BLM after a period of comment by public organizations, the petroleum industry, and state and federal governmental entities. The updates are often published in a Record of Decision (ROD) that may include modification of the RFD for a particular RMP. In addition to reviewing all RODs issued since the Phase I work, this current analysis also examined whether any new RMPs had been released covering geographic areas not previously considered. Table 5-1 below shows a summary of the RMPs considered for generating 2018 scaling factors and the minimum and maximum foreseeable development scenarios where available. The minimum and maximum well counts in an RFD were determined for calendary year 2018 by linearly interpolating the RMP prediction if the RMP plan extended beyond 2018, and used the published RFD scenario if that scenario was to be completed before 2018. Although only the average growth statistics were used to determine 2018 emissions projections, the minimum and maximum scenarios give an indication of the range of predicted activity. Figure 5-1 shows the geographic coverage of the RMPs used to generate 2018 scaling factors.

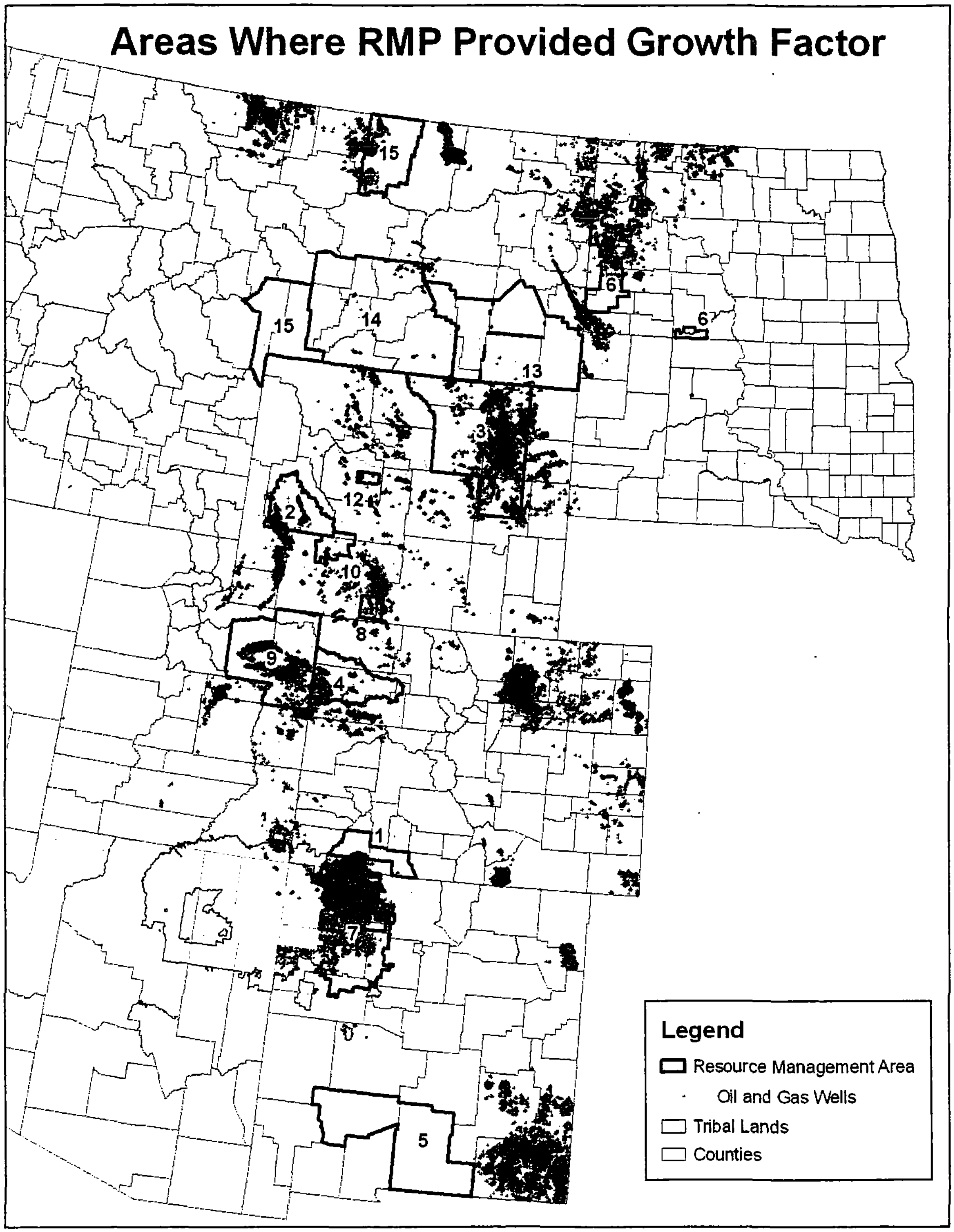


Figure 5-1. Geographic coverage of RMPs used to generate scaling factors for 2018 emissions projections. RMPs by number are listed in Table 5-1.

Table 5-1. BLM RMPs considered for use in generating 2018 scaling factors, and the predicted minimum and maximum well counts.

		2018							
		Gas Wells		Oil Wells		CBM Wells		Comp. Stations	
RMP Name	#	Min	Max	Min	Max	Min	Max	Min	Max
Northern San Juan Basin Coal Bed Methane Project*	1					117	514	6	15
Pinedale RMP	2	3,948	5,502						
Wyoming Powder River Basin Final EIS*	3	1,165	2,863			13,872	35,223	313	948
White River Resource Area RMP EIS	4		1,006						
RMP EIS for Mineral Leasing and Development in Sierra and Otero Counties*	5		27		37				
Dakota Prairie Grasslands Oil and Gas Leasing	6		655				87		
Farmington Proposed RMP and Final EIS	7	3,653	10,746	104	308	815	2,399		
Desolation Flats Natural Gas Field Development Project	8	51	275						
Draft Vernal Resource Management Plan	9		3,530		1,670		106		
Jack Morrow Hills Coordinated Activity Plan*	10	157	262			21	42		
Wind River Natural Gas Project	11	233	485						
Powder River and Billings RMPs – Powder River	12		610				13,867		
Powder River and Billings RMPs – Billings	13		190				4,876		
Powder River and Billings RMPs – Special Consideration	**14**		114						
Sweetwater and Carbon Counties, Wyoming*	15	805	2,857						

* Indicates RMPs for which updated information was available since the Phase I inventory analysis was conducted.

As shown in Table 5-1, the RMPs obtained covered a large portion of the WRAP production areas. In addition to the BLM studies, the Alaska Department of Natural Resources prepares 20-year production forecasts that were used in this effort (AK DNR, 2006). For the remaining areas, regional production forecasts published by the Energy Information Administration were used[3]. For those areas where EIA forecasts were the only source of data identified, separate oil and gas growth factors were calculated as the 2018 regional production forecast by the EIA divided by 2005 regional production reported by the EIA. There are three EIA growth regions in which some portion of emissions in that region were projected using EIA data. Growth factors developed for those regions based on the EIA's production forecasts are shown in Table 5-2.

Table 5-2. 2005 to 2018 oil and gas growth factors based on EIA forecasts.

Region	Oil Production	Gas Production
Rocky Mountain	1.5515	1.2072
Southwest	0.9852	1.0632
West Coast	1.0730	0.7232

Projections to 2018 based on the BLM RMPs or Alaska DNR data were made using growth factors derived from the proposed future development and the actual 2005 activity as developed in the scale-up of the baseline EI from 2002 to 2005. In order to estimate the future number of wells, both the number of wells installed and the number of wells plugged and abandoned had to be estimated. As the RMPs do not include estimates of the number of wells that will be plugged and abandoned in future years, OGC data were used to estimate the number of wells plugged and abandoned annually at the county level. The future number of wells in a production area was then estimated based on the number of existing wells in 2005, the number of new wells anticipated by the RMP and the estimated number of wells that would be plugged and abandoned based on the assumed persistence of historical well plugging rates.

For growth factors in counties that fall within an RMP area, it was necessary to intersect the RMP area boundaries with the counties' boundaries to determine the fraction of the county that lies within the RMP. This intersection was conducted using 2005 well counts and yielded three distinct conditions: counties entirely within an RMP area, counties partially within an RMP area and counties not in an RMP area. In counties completely within an RMP area, and counties not in an RMP area, the RMP-based growth factor and the EIA-based growth factor were used respectively. In the counties only partially intersected by an RMP area, it was necessary to apply RMP-based growth factors to the fraction of the wells in the RMP area and EIA-based growth factors to the remaining wells. This was done according to Equation 5-1.

Equation 5-1:

$$GF_{county} = \sum_i \left(\frac{N_{wells,RMP_i}}{N_{wells,county}} \times GF_{RMP_i} \right) + \frac{N_{wells,NON-RMP}}{N_{wells,county}} \times GF_{EIA}$$

where GF_{county} is the county growth factor (for counties with both RMP and non-RMP areas), N_{wells,RMP_i} is the number of wells in the county that lie within the boundaries of RMP i, $N_{wells,county}$ is the total number of wells in the county, GF_{RMP_i} is the growth factor for RMP i, $N_{wells,NON-RMP}$ is the number of wells in the county that do not lie within the boundaries of any RMP, and GF_{EIA} is the growth factor for the county based on the EIA.

It should be noted that it was not possible to derive growth factors based on well count for all cases where the 2002/2005 estimates were based on well count. RMPs were the only source of well count projections available, and the RMPs did not cover all areas for which the updated methodology in this analysis was applied. In addition, some counties' growth factors were a weighted average of both RMP-based and EIA-based growth factors, as described in Equation 5-1, which combines both a production-based and a count-based growth factor estimate. This was due to the limited number of RMPs available for the entire WRAP region.

For drilling activities, a separate growth factor was developed based on the predicted drilling activities in RMPs and a drilling-based growth factor from the 2007 Annual Energy Outlook[3]. In areas with coverage by an RMP, a separate growth factor was estimated for drill rig activity as the number of wells drilled per year suggested by the development scenario divided by the number of wells drilled in the same area in 2005. A growth factor for drilling in areas where EIA forecasts were used was determined based on the total predicted growth in well drilling in the lower 48 states as reported in the EIA forecast; regional drilling growth was not available. Based on the EIA information, a drill rig activity growth factor of 1.071 was calculated. To determine the drilling activity growth factor for counties lying partially within the boundaries of an RMP, a well-count weighted average of the drilling growth factors in the RMP and outside of the RMP was derived, in a manner similar to Equation 5-1.

Independent 2018 emissions estimates

There were counties for which there was predicted O&G activity in 2018, but no activity in 2005, and therefore a growth factor for these counties needed to be developed independently of the methodology described above. In cases of counties entirely or partially within an RMP area, an independent methodology was employed to estimate 2018 emissions.

For these counties, the fraction of 2005 wells within the county that were also within the RMP was determined by intersecting the county and RMP boundaries. This fraction was applied to the predicted RMP well count for 2018 to determine the predicted county-level number of wells in 2018. For each source category, the 2005 emissions per well were determined by totaling the 2005 emissions by pollutant for each source category and dividing by the number of wells. This was then multiplied by the number of predicted wells in 2018 to estimate the emissions from the RMP fraction of the county's wells in 2018. The remaining portion of the county outside of the RMP was assumed not to have any O&G activity in 2018, since it had no activity in 2005 and no RMP to indicate any planned future activity. It should be noted that for counties with no 2005 activity and no RMP, it was assumed that no future O&G activity would be assigned to that county.

Future Year Emission Controls

Implementation of new federal and state control programs will have a substantial impact on future emissions. Known "on the books" state and federal emissions control estimates were incorporated into the 2018 emissions projections. A summary of the controls identified and the actions taken to incorporate them into the 2018 projections is provided in Table 5-3. It should be noted that state controls in Wyoming and Utah were not applied to the baseline 2002/2005 emissions because it was assumed that the in-use equipment at that time predated the control regulations in both of these states. However, by 2018 it is assumed that 100% of the equipment would be subject to these state regulations.

Table 5-3. Future federal and state controls incorporated into the 2018 emissions projections.

State	Future Controls	Action
All	Federal onroad diesel engine standards (EPA, 2005b)	Used emissions standards information for 750+ hp drill rig engines from EPA's NONROAD model to adjust drill rig engine emissions for future performance standards
All	Federal nonroad spark-ignition engine standards (EPA, 2005b)	Used emissions standards information for natural gas fired nonroad engines (SCC 2268000000) from EPA's NONROAD model to adjust CBM pump engine emissions for future performance standards
All	Federal mandates for non-road diesel fuel sulfur content (EPA, 2000)	Used 2002 study by WRAP (Pollack, A., Chan, L., Chandraker, P., Grant, J., Lindhjem, C., Rao, S., Russell, J., Tran, C., 2006) to determine ratio of 2002 to 2018 non-road diesel fuel sulfur content and used this to develop scaling factors for SOx emissions from drilling rigs.
Wyoming	Best Available Control Technology (BACT) regulation requiring all permitted O&G sources in the state to emit no more than 1 g/bhp-hr NOx emissions.	The 2002/2005 emissions estimates per compressor engine were modified for 2018 by assuming this maximum BACT emissions factor. The ratio of 2018 per equipment emissions to 2002 per equipment emissions was estimated to derive a control factor by county in Wyoming.
Utah	BACT regulation requiring all permitted O&G sources in the state to emit no more than 1 g/bhp-hr NOx emissions.	A similar methodology to that in Wyoming was employed to generate control factors for Utah compressors.
Colorado	Regulation 7 requiring reductions in VOC emissions from oil and gas sources, controls requirements for compressor engines, tanks, and glychol dehydrators.	All wellhead compressors in Colorado are assumed to be part of Colorado's point source inventory and thus were not considered in this area source inventory.

The 2018 drill rig and CBM pump emissions were adjusted downward under the assumption that future equipment purchases will be required to meet the federal nonroad engine standards. The adjustment for drill rig emissions was performed by comparing the emission rates yielded by EPA's NONROAD model for 750+ horsepower drill rig engines in 2018 versus those for the same category in 2002; this ratio is based on the model's assumption about engine lifetimes and fleet turnover rates. For CBM pump engines, the adjustment was performed by comparing the emission rates given by the NONROAD model for natural gas fired engines in 2018 versus those for the same category in 2002. For drill rig SOx emissions, the ratio of 2018 non-road sulfur fuel content (assumed to be 15 ppm) to the by-county sulfur content of non-road diesel fuel in 2002 was determined. This determined the fraction of SOx emissions reductions for this source category, assuming all of the fuel sulfur would be emitted as SOx. In Wyoming and Utah, the 2002/2005 compressor engine estimates in the focus basins were modified under the assumption that the maximum emissions factor of NOx for these engines would be 1 g/bhp-hr. The county-level emissions per equipment were generated and a ratio was derived of the 2018 emissions to the 2005 emissions. This was used to derive a control factor which was applied to all compressor emissions in these two states.

2018 EMISSIONS ESTIMATES

The 2018 projected emissions for NOx and SOx are shown in Tables 5-4 and 5-5, respectively. The oil and gas point sources from the current WRAP emissions inventory are also shown below in Tables 5-4 and 5-5 for comparison, as well as the total of oil and gas point and area sources. Table 5-4 shows that for drilling rigs, Wyoming has the largest projected NOx emissions, followed by New Mexico and Colorado. This is due to the projection of 2018 emissions from a baseline year of 2005, when there was significant gas well drilling activity happening in Wyoming. For gas compressor engines, New Mexico has the greatest emissions due to the significant use of wellhead compression in the San Juan Basin. It should be noted that Colorado wellhead compressor emissions were not estimated because this equipment is counted in the Colorado point source inventory.

Table 5-4. NOx emissions estimates by source category for all WRAP states in 2018.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	452	0		0		453	36,382	**36,835**
Arizona		0	8	7		15	382	**397**
California							10109	**10,109**
Colorado[b]	4,413	12	4,006	24,687	400	33,517	14,825	**48,342**
Idaho							1,734	**1,734**
Montana	2,821	126	3,946	6,987		13,880	2,533	**16,413**
Nevada	21	2	40	0		63	47	**110**
New Mexico	5,343	522	47,599	20,183	67	73,714	36,320	**110,034**
North Dakota	1,655	126	18,399	689		20,869	3,928	**24,797**
Oregon		0	37	7		44	753	**797**
South Dakota	118	6	368	66		557	311	**868**
Utah	944	122	164	5,066		6,297	1,930	**8,227**
Washington							247	**247**
Wyoming	9,883	147	655	22,449	1,008	34,142	9,075	**43,217**
WRAP Total	**25,652**	**1,063**	**75,222**	**80,140**	**1,475**	**183,551**	**118,576**	**302,127**

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory

b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

Wellhead emissions sources from gas wells in Colorado include heaters, well completions and well flaring and venting, which were estimated in the Phase I work but not updated in this analysis. Any future emissions inventory effort should investigate these sources in more detail.

Table 5-5 shows that SOx emissions in the WRAP region are expected to be quite small in 2018 for the sources estimated, largely due to the phase-in of federally mandated low-sulfur fuel standards for non-road diesel fuel. Thus although a significant growth in activity was predicted for O&G drilling in the western U.S. by 2018, this is more than matched by the control factor caused by the new fuel.

Table 5-5. SOx emissions estimates by source category for all WRAP states in 2018.

States	Drill Rigs	Oil Well - All Sources	Compressor Engines	Gas Well - All Sources	CBM Pump Engines	All Area Sources	All Point Sources	TOTAL
Alaska[a]	1	0		0		1	79	**80**
Arizona		0	0	0		0	0	**0**
California							997	**997**
Colorado[b]	11	0	0	0	0	11	129	**140**
Idaho							10	**10**
Montana	6	0	0	0		6	16	**22**
Nevada	0	0	0	0		0	0	**0**
New Mexico	3	0	1	7	0	12	12,990	**13,002**
North Dakota	4	0	0	0		4	2,672	**2,676**
Oregon		0	0	0		0	8	**8**
South Dakota	0	0	0	0		0	15	**15**
Utah	1	0	0	0		1	0	**1**
Washington							4	**4**
Wyoming	3	0	0	0	0	3	6,420	**6,423**
WRAP Total	**29**	**0**	**1**	**7**	**0**	**38**	**23,340**	**23,378**

a – Wellhead compressors in Alaska are permitted as part of a central station and counted in the state point source inventory
b – Colorado's point source inventory threshold is 2 tpy NOx, which includes all wellhead compressors, therefore the only compressor emissions listed here for Colorado are those from the Southern Ute tribal lands.

It should be noted that some minor emissions are predicted from source categories that are only estimated in New Mexico, such as artificial lift engines and SWD engines. These source categories have been identified as a result of the NMED study in San Juan and Rio Arriba counties. Due to the focused effort of that EI, some equipment was identified which had not been inventoried in other regions of the WRAP domain. Future emissions inventories should include these source categories in all areas.

Figure 5-2 shows the estimated trend of NOx area source emissions from this analysis for the WRAP region for 2002, 2005 and 2018. In Wyoming, and to some extent Colorado and Utah, the effects of controls requirements on area source emissions categories can be observed, since in Wyoming area source emissions are predicted to decrease in 2018 as compared to 2005 despite increased growth in O&G activity. In Colorado and Utah the projected growth in area source emissions from 2005 to 2018 is quite small. North Dakota area source emissions are projected to jump dramatically from 2005 to 2018, largely due to the assumed implementation of the RFD in the Dakota Prairie Grasslands RMP. New Mexico area source emissions are predicted to continue to increase from 2005 to 2018.

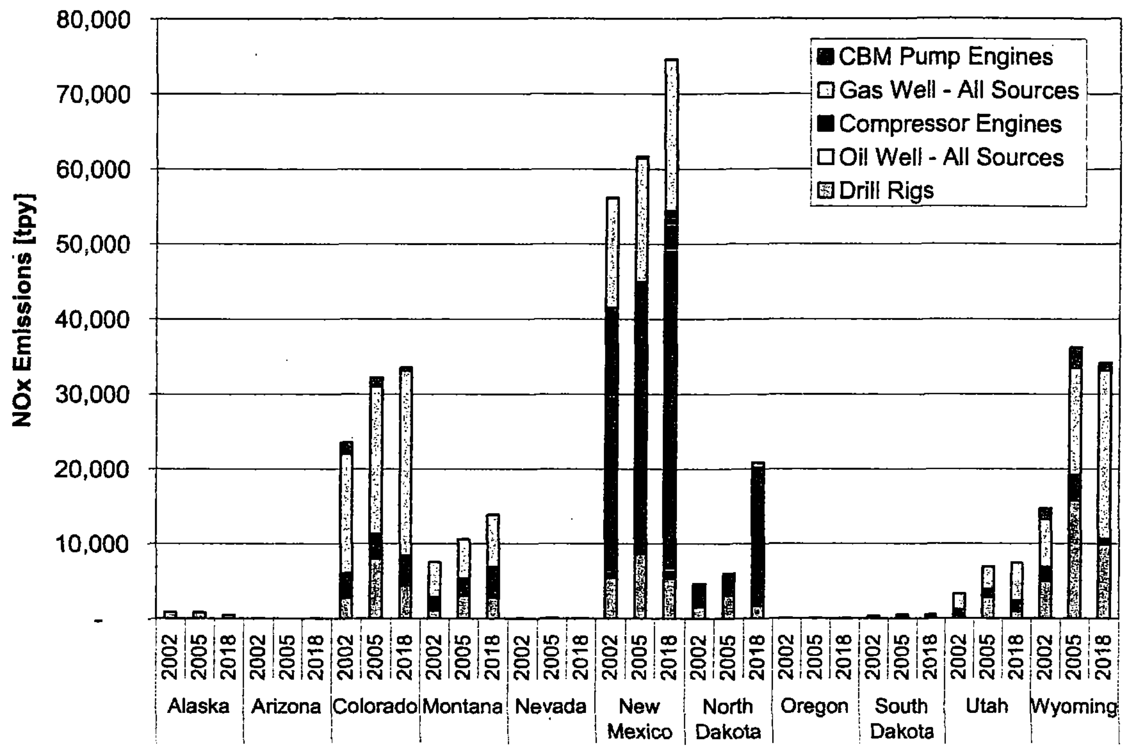


Figure 5-2. NOx area source emissions estimates by state in the WRAP region for 2002, 2005, and 2018.

Figure 5-3 shows the estimated trend of SOx area source emissions from this analysis for the WRAP region for 2002, 2005 and 2018. In all states the SOx area source emissions are predicted to grow significantly from 2002 to 2005 driven by large-scale oil and gas exploration in the WRAP region during this time frame. However, by 2018 these emissions are expected to decrease dramatically as the EPA-mandated phase-in of low sulfur non-road diesel fuel is put into effect. Drilling rig engines are by far the largest source of SOx area source emissions from all O&G area source categories.

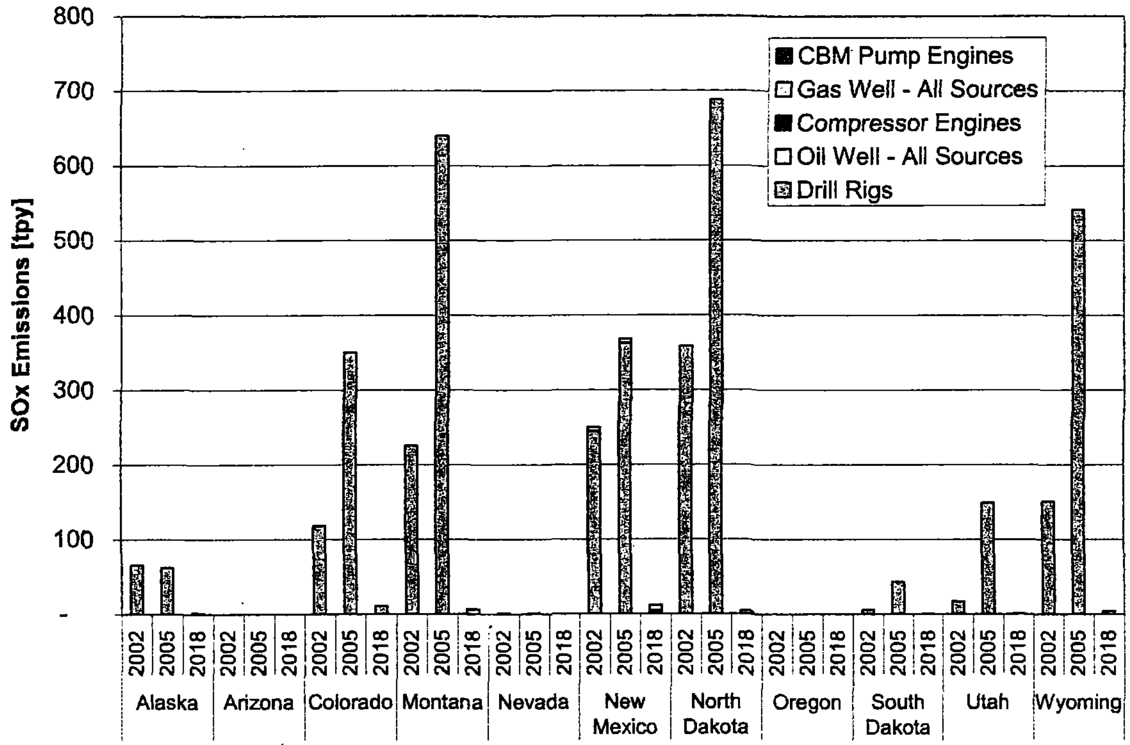


Figure 5-3. SOx area source emissions estimates by state in the WRAP region for 2002, 2005, and 2018.

Comparison of Phase I and Phase II 2018 Estimates

Figure 5-4 shows the projected 2018 NOx emissions from the Phase I and Phase II analyses. In all states that have been updated in this current analysis except Colorado, NOx emissions are seen to decrease relative to the Phase I analysis. This is due to the assumption of fewer wellhead compressors being used in states like Wyoming and Utah, and the improved estimates of drilling time per well in these areas. In Colorado a net increase in NOx emissions is predicted, but this is largely due to the addition of the Southern Ute tribal inventory in 2002, which had not been previously considered, and the subsequent growth of the tribal emissions to 2018.

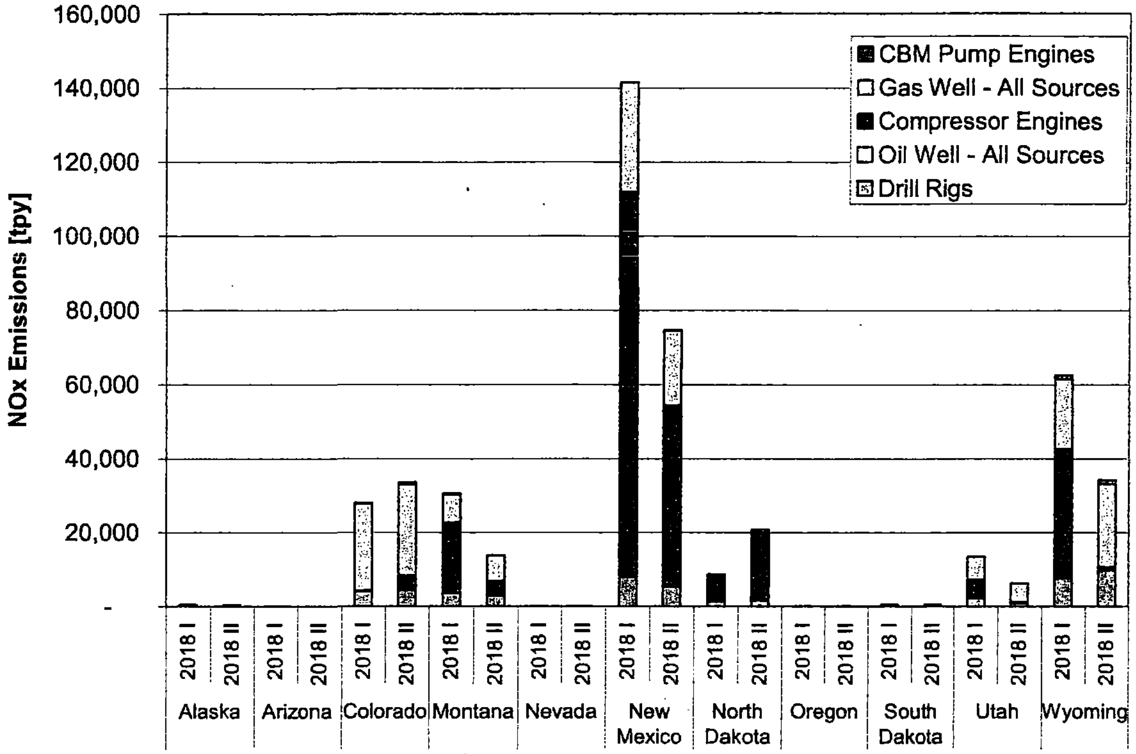


Figure 5-4. 2018 NOx emissions estimates by state in the WRAP region from the Phase I and Phase II analyses.

Figure 5-5 shows the projected 2018 SOx emissions from the Phase I and Phase II analyses. In Utah and Wyoming, there is a significant reduction in SOx emissions relative to the Phase I analysis. This is due largely to an improved estimate of the drilling time, since drilling rigs are the major source of SOx emissions from O&G area sources. In Colorado there is a slight increase in SOx emissions – this is due to the inclusion of the Southern Ute tribal inventory which had not previously been accounted for in Colorado's O&G area source inventory. In New Mexico, the NMED inventory estimated a number of source categories that contribute to SOx emissions but which were not estimated elsewhere in the WRAP region.

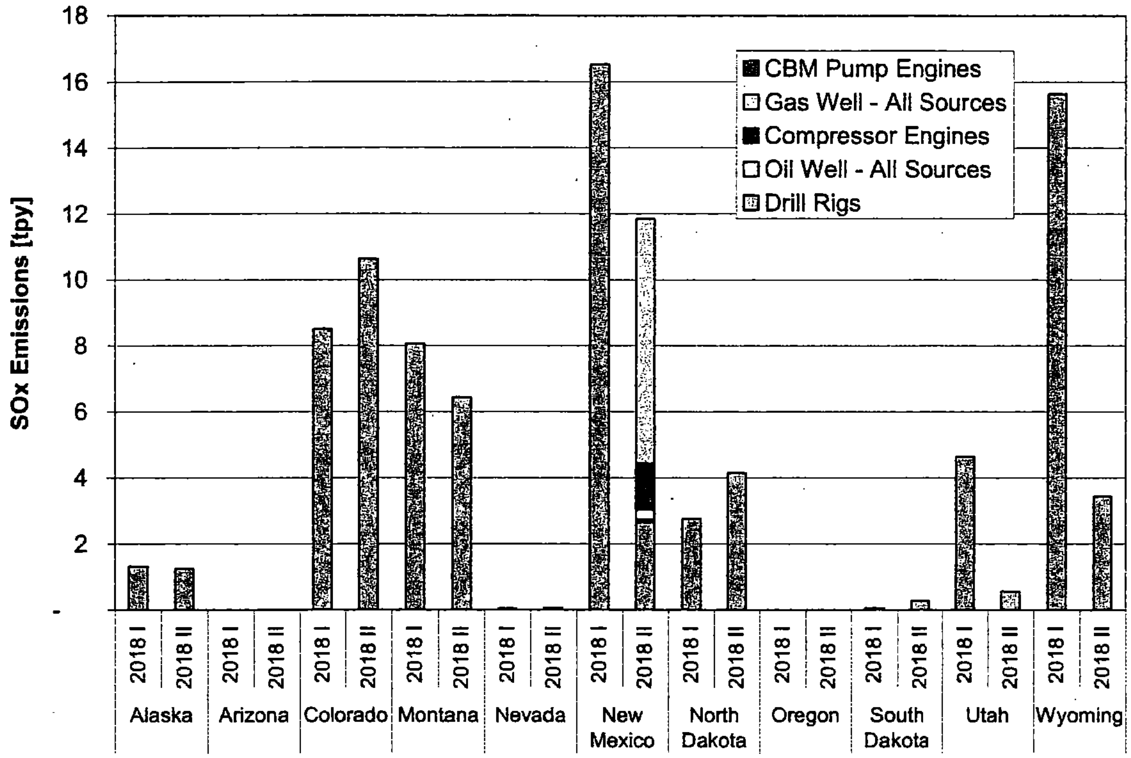


Figure 5-5. 2018 SOx emissions estimates by state in the WRAP region from the Phase I and Phase II analyses.

6. SOx POINT SOURCE PROJECTIONS

An additional task undertaken as part of this analysis was to update projections of SOx emissions from large O&G point sources in the WRAP region in 2018. Previous efforts to estimate 2018 projections of SOx emissions from large gas processing plants and compressor stations in the WRAP region did not take into account potential control technologies being leveraged by gas producers to reduce SOx emissions from these sources. The previous efforts also use Annual Energy Outlook (AEO) factors which did not necessarily reflect accurate growth projections for gas production in 2018, and thus this analysis is tasked with revising these projections.

The methodology employed to revise these projected emissions began with identifying the large natural gas processing plants and compressor stations in the WRAP region that had high SOx emissions. These emissions are generally due to the processing of "sour gas" – that is gas with a significant concentration of H_2S. This was done by accessing the point source database that WRAP had already compiled, which was based largely on information obtained directly from the permitting requirements of the respective state agencies. The list of identified gas plants is listed in Table 6-1.

Table 6-1. Major SOx emitting gas processing plants in the WRAP region.

Plant Name	Plant ID Number	Operator	City	County	State
Brady Gas Plant	5603700008	Anadarko	Rock Springs	Sweetwater	Wyoming
Whitney Canyon Gas Plant	5604100012	BP	Evanston	Uinta	Wyoming
Lost Cabin Gas Plant	5601300028	Burlington	Lysite	Fremont	Wyoming
Carter Creek Gas Plant	5604100009	Chevron	Evanston	Uinta	Wyoming
Beaver Creek Gas Plant	5601300008	Devon (formerly Santa Fe Synder)	Riverton	Fremont	Wyoming
Elk Basin Gas Plant	5602900012	Encore Energy (formerly Howell Petroleum	Powell	Park	Wyoming
Shute Creek Facility	5602300013	Exxon	Kemmerer	Lincoln	Wyoming
Worland Gas Plant	5604300003	Highland Partners	Worland	Washakie	Wyoming
Oregon Basin Gas Plant	5602900007	Marathon Oil	Cody	Park	Wyoming
Dagger Draw Gas Plant	350150285	Agave (formerly Duke Energy)	Artesia	Eddy	New Mexico
Maljamar Gas Plant	350250004	Conoco (formerly Frontier Field Services)	Maljamar	Lea	New Mexico
Denton Gas Plant	350250007	Davis Gas Processing	Lovington	Lea	New Mexico
Artesia Gas Plant	350150011	Duke Energy	Artesia	Eddy	New Mexico
Eunice Gas Plant	350250044	Duke Energy	Eunice	Lea	New Mexico
Linam Ranch Gas Plant	350250035	Duke Energy	Hobbs	Lea	New Mexico
Indian Basin Gas Plant	350150008	Marathon Oil	Carlsbad	Eddy	New Mexico

Plant Name	Plant ID Number	Operator	City	County	State
Jal No. 3 Gas Plant	350250008	Sid Richardson	Jal	Lea	New Mexico
Eunice Gas Plant	350250060	Targa Midstream Services (formerly Dynergy)	Eunice	Lea	New Mexico
Monument Gas Plant	350250061	Targa Midstream Services (formerly Dynergy)	Hobbs	Lea	New Mexico
Saunders Gas Plant	350250063	Targa Midstream Services (formerly Versado Gas Processors)	Lovington	Lea	New Mexico

Title V permits were obtained for all of these sources from the Wyoming Department of Environmental Quality (WYDEQ) and from NMED. These permits contained information on the maximum SOx potential-to-emit from all of these plants, and some indication of whether any control technology was expected to be utilized. In many cases, this information was not available from the permit document, and thus a survey was made of all plant operators in Table 6-1. Survey results indicated that many of these plants either already had in place a control system, or were planning to implement a control system by 2018. The control system most often used was an acid gas injection (AGI) system, which chemically binds to the SOx and converts it to a liquid which is then re-injected into deep wells. Such a system is expected to have an efficiency of 98% in removal of SOx O_2 and this was the control factor assumed for all plants using this technology. Although this technology requires a periodic shut-down and venting of the acid gas, the emissions associated with the shut-down were not accounted for in determining the revised 2018 emissions projections.

In most cases the Title V permits of these plants indicated the potential-to-emit, but not the actual emissions. Actual emissions were reported only if a major change to the plant had been conducted. As part of the survey of plant operators, the actual SOx annual emissions in 2005 were obtained for most plants – for those plants where this information was not obtained, the 2005 emissions were assumed to be identical to the potential-to-emit. In determining the growth factors to apply to each plant, the survey also asked the plant operators to provide information on projected growth in operation of these plants. All plant operators indicated that no growth was expected in gas throughput of these plants and in some instances was expected to decrease. Based on declining production over the past several years, the Whitney Canyon Gas Plant in Wyoming was expected to not be economical to operate by 2018 and therefore based on a regression curve was projected to have zero emissions by 2018. Based on this information, this analysis assumed a no-growth scenario for baseline 2018 emissions. AGI control factors were then applied to the plants that indicated such a system would be in operation by 2018. The results of these projections are shown in Table 6-2.

Table 6-2. Projected 2018 SOx emissions from large point-source gas processing plants in the WRAP region.

Plant Name	Plant ID Number	Operator	State	Previous 2018 SO_2 Emissions [tpy] (Pechan)	Updated 2018 SO_2 Emissions [tpy]
Brady Gas Plant	5603700008	Anadarko	Wyoming	210	181
Whitney Canyon Gas Plant	5604100012	BP	Wyoming	9172	0
Lost Cabin Gas Plant	5601300028	Burlington	Wyoming	3170	2378
Carter Creek Gas Plant	5604100009	Chevron	Wyoming	1184	284
Beaver Creek Gas Plant	5601300008	Devon (formerly Santa Fe Synder)	Wyoming		42
Elk Basin Gas Plant	5602900012	Encore Energy (formerly Howell Petroleum	Wyoming	2136	1500
Shute Creek Facility	5602300013	Exxon	Wyoming	2651	1260
Worland Gas Plant	5604300003	Highland Partners	Wyoming		318
Oregon Basin Gas Plant	5602900007	Marathon Oil	Wyoming	438	350
Dagger Draw Gas Plant	350150285	Agave (formerly Duke Energy)	New Mexico	230	243
Maljamar Gas Plant	350250004	Conoco (formerly Frontier Field Services)	New Mexico	3373	3574
Denton Gas Plant	350250007	Davis Gas Processing	New Mexico	399	295
Artesia Gas Plant	350150011	Duke Energy	New Mexico	1134	19
Eunice Gas Plant	350250044	Duke Energy	New Mexico	953	55
Linam Ranch Gas Plant	350250035	Duke Energy	New Mexico	1261	26
Indian Basin Gas Plant	350150008	Marathon Oil	New Mexico	2794	1100
Jal No. 3 Gas Plant	350250008	Sid Richardson	New Mexico	1633	1231
Eunice Gas Plant	350250060	Targa Midstream Services (formerly Dynergy)	New Mexico		25
Monument Gas Plant	350250061	Targa Midstream Services (formerly Dynergy)	New Mexico	1159	1432
Saunders Gas Plant	350250063	Targa Midstream Services (formerly Versado Gas Processors)	New Mexico		28

7. 2018 EMISSION CONTROL SCENARIOS

The 2018 emissions inventory described in Section 5 of this report, and the control strategies developed in Section 4 of this report, form the basis for a control scenario analysis. The analysis demonstrates a potential scenario in which controls for drilling rigs and compressor engines are applied to the emissions inventory for the San Juan Basin in New Mexico. Some control measures for each of these two source categories are applicable only to certain types of engines. For example lean burn compressor engines are not compatible with non-selective catalytic reduction systems – and thus it is not possible to apply both measures to a single compressor engine. Similarly some drilling rig measures will not apply to the diesel generators that are used on some drilling rigs because these generators do not operate at sufficient load or have a very low maximum horsepower. The exact mix of compressor engines and drilling rigs in the population of this equipment in a particular basin is not known. As described in previous sections, this inventory makes use of basin-wide average assumptions and does not attempt to catalog individual pieces of equipment in use on oil and gas fields in any basin. Thus the exact desired or possible mix of control technologies to be applied to engines in the field is not known.

In light of this limitation, two scenarios are presented here for the San Juan Basin in New Mexico. In the first scenario, conservative assumptions are made about the application of all control measures to the inventory – for drilling rigs there are 7 control measures applied and for compressor engines there are 8 measures applied. Specifically, each of the control measures for compressors and drilling rigs are assumed to apply to 5% of the equipment population. For drill rigs in the San Juan Basin this scenario therefore applies to a total of 35% of all of the rigs operating in the basin, and for compressor engines this scenario applies to 40% of all of the compressor engines operating in the basin. This is a fairly aggressive penetration rate of control technologies, but given the regulations that have been enacted in states like Wyoming, Utah and Colorado, the overall equipment penetration rate is reasonable.

In the second scenario a single example control measure is applied to the emissions inventory for San Juan Basin and is presented to give a tool for quantifying the emissions reductions from a single control measure. In the case of drilling rigs, the example control measure is a selective catalytic reduction system (DRE-2) and for compressor engines it is a combination of an air-fuel ratio controller (CE-2) and non-selective catalytic reduction (CE-1). CE-2 and CE-1 are applied in tandem because a NSCR system typically requires a carefully-controlled air-fuel ratio in the engine to operate at optimal conditions[22].

The emissions reductions for the basin are estimated according to equation 8-1:

$$E_{NOx,red,i} = CF_i \times P_i \times E_{NOx,drillrigs}$$

where $E_{NOx,drillrigs}$ is the NOx emissions from drilling rigs in the basin in tons, P_i is the penetration rate of control measure i in the basin, CF_i is the control factor control measure i in the basin, and $E_{NOx,red,i}$ is the NOx emissions reduction from control measure i applied to drilling rigs in the basin in tons. The costs of applying these control measures to the drilling rigs in the basin are estimated according to equation 8-2:

$$C_{Basin} = \sum_i E_{NOx,red,i} \times CE_i$$

where CE_i is the cost-effectiveness in \$/ton-NOx of control measure i for drilling rigs and C_{Basin} is the total cost of all control measures applied to drilling rigs. Thus this methodology uses the basin total NOx emissions for drillings rigs and the cost-effectiveness of each control measure for drillings rigs to estimate emissions reductions and cost for the basin, and does not require knowledge of the number of drilling rigs operating in the basin. A similar methodology is used for the compressor engines.

Table 7-1 shows NOx emissions reductions only from an example scenario using the 7 drilling rig control measures discussed above in the San Juan Basin, with each control measure applied with a 5% penetration rate. Table 7-2 below shows the associated cost estimates for this example scenario.

Table 7-1. NOx emissions reductions from application of all drilling rig control measures at a 5% penetration rate to the drilling rig NOx emissions inventory for the San Juan Basin.

State	Basin	County FIPS	SCC	NOx Reduction [tpy]	VOC Reduction [tpy]	CO Reduction [tpy]	SOx Reduction [tpy]
New Mexico	San Juan South	35031	2310000220	7	-0.01	0	0
		35039	2310000220	107	-0.55	0	0
		35043	2310000220	0	0.00	0	0
		35045	2310000220	164	-0.81	0	0
		Basin Total		**279**			

Table 7-2. Cost estimates for the entire San Juan Basin from application of all drilling rig control measures at a 5% penetration rate to the drilling rig NOx emissions inventory for this basin.

County	Cost
35031	\$170,530
35039	\$1,547,020
35043	\$4,594
35045	\$2,765,373
Total Lifetime Cost	**\$4,487,518**

Detailed calculation spreadsheets to estimate emissions control scenarios are provided in Appendix A.

8. CONCLUSIONS AND RECOMMENDATIONS

An analysis of O&G area source emissions has been conducted for the WRAP region, which serves as an update to the previous Phase I effort. This analysis focused on NOx emissions, and specifically on drilling rigs and wellhead compressor engines as large sources of NOx emissions from this activity. NOx and SOx emissions were estimated for 2002, 2005, and projected to 2018 on a basin-wide level, a county level and a state level. The results indicate that significant growth has already occurred in O&G related area source emissions from 2002 to 2005, which largely tracks the tremendous growth in this industry in the western regional U.S. Projections to 2018 show that for some states the growth is projected to continue, but other states that have enacted control measures may begin to see a reduction in NOx emissions from these sources – particularly Wyoming and Utah which have both enacted BACT regulations on O&G area sources. SOx emissions are expected to decrease in 2018 relative to current levels, primarily due to the introduction of low-sulfur diesel fuel as mandated by the EPA. Despite these decreases, O&G area source emissions are expected to continue to be a compliance concern for states in the foreseeable future. Control technologies were identified for many categories of emissions that were determined to be both effective in terms of reducing emissions but also determined to be cost-effective when compared to other measures adopted by State Implementation Plans.

As part of the Phase II inventory process, ENVIRON identified several categories for which more information, or more detailed information, could aid in improving the emissions inventory estimates for the WRAP region.

Drilling rig and compressor engine emissions factors should be obtained for additional pollutants such as VOC, CO, PM and HAPs. This information should be compiled for all engine types. Furthermore, future work should track the maturity of fields to improve estimates of the ratio of wellhead, lateral and central compression being used in particular basins. The same detailed inventory approach that was used for compressors and drilling rigs should be applied to other source categories, such as heaters, well completions, salt-water disposal engines, and CBM pump engines. The focus basins in the Phase II effort should be expanded to include other high activity areas such as Montana, North Dakota, and Alaska.

VOC sources should be inventoried in a future phase of this work. VOCs were not considered a focus of this inventory effort, which largely focused on NOx emissions for regional haze issues. Some major VOC source categories that would need to be examined are flaring, venting/breathing losses, pneumatic devices, glycol dehydrator units, tanks and heaters, and other minor VOC sources. Because a future improved VOC inventory would gather information about losses of natural gas due to venting and breathing, this information would also apply to methane emissions rates – a key greenhouse gas. Similarly, CO_2 emissions should also be estimated in order to obtain a complete greenhouse gas emissions inventory from oil and gas area sources.

More detailed information is the key to improving a region-wide inventory such as this. Future work should include more detailed information from producers, as well as from additional producers. A coordinated effort to contact producers as a group would greatly facilitate this process – indeed the cooperation of the Independent Petroleum Association of the Mountain States (IPAMS) was helpful in obtaining producer information from medium-sized or independent producers as a group. Drilling rig companies should be included in any future survey effort, since much of the drilling is conducted by contracting companies and not by the producers or well owners. This would eliminate the need to use the producers as middle agents to transfer the information about drilling activities.

Similarly any future emissions inventory effort would make use of new and more detailed information from the state OGCs about well counts and production in each state. These OGC databases are frequently updated, even for past years, as more information about wells and production are made available.

New Resource Management Plans (RMPs) and Environment Impact Reports (EIRs) that deal with oil and gas development in the WRAP region are emerging. These should be incorporated into future emissions inventories. Finally, this well-specific information should be utilized to generate new spatial surrogates for allocating these emissions for modeling purposes. Previous spatial surrogates were based on 2002 data, which is reasonable for in-fill activity, but does not capture well any new exploration activity occurring in these regions.

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APPENDIX A

(Available on the WRAP Stationary Sources Joint Forum Oil/Gas Workgroup website: http://www.wrapair.org/forums/ssjf/documents/eictts/oilgas.html)

Example Controls Scenario for the San Juan Basin, New Mexico

APPENDIX B

Survey Questionnaire for Oil and Gas Producers

Introduction

ENVIRON Corporation, under contract to the Western Regional Air Partnership (WRAP), has been developing estimates of 2002 and 2018 non-point-source (area source) oil and gas (O & G) operations in the WRAP region, which includes the states of Alaska, California, Oregon, Washington, Idaho, Montana, Wyoming, Colorado, Arizona, New Mexico, and North and South Dakota. Emissions estimates derived in Phase I of this work were based on available information from state Oil and Gas Commissions (OGCs), assumptions and estimates of O & G activity in 2002, and projected growth in O & G activity. The Phase I final report on 2002 WRAP regional emissions estimates and projected 2018 emissions estimates can be found at: http://wrapair.org/forums/ssjf/documents/eictts/oilgas.html

After the Phase I WRAP work, ENVIRON prepared a detailed emissions inventory of all oil and gas area source emissions in San Juan and Rio Arriba counties in New Mexico in 2002, under contract to the New Mexico Environment Department (NMED). This emissions inventory was based on a detailed survey of O & G producer activities in the two counties and relied on a high response rate from producers operating in these counties. The final report of the NMED analysis can be found at:
www.nmenv.state.nm.us/aqb/projects/San_Juan_Ozone/NM_Area_Emissions_report.pdf

Based on these two previous analyses, ENVIRON is now engaged in a Phase II updated emissions inventory estimate for the WRAP region for 2002 and updated emissions projections for 2018. In addition, ENVIRON has been asked by WRAP to identify and quantify potential control strategies to reduce these emissions and the potential emissions reductions. The Phase II work will rely on detailed producer information for all basins in which major O & G operations are occurring. Emissions estimates will be made on a well-count basis where possible, and averaged by basin in the WRAP region. A high response rate from producers to this request for information will ensure that this new inventory will be both detailed and accurate.

The purpose of this questionnaire is to assist in the preparation of these updated 2002 and 2018 oil and gas emissions inventories. In this project, we will also be assessing the emission sources that have significant potential for reducing emissions through various control methods and technologies. The potential emissions reductions from the most promising control technologies will be evaluated for each western state and an estimate of the potential reductions in 2018 will be provided.

This document contains a detailed list of questions to producers – by emissions category – that will aid in estimating 2002 and 2018 emissions inventories. This document makes reference to the workplan developed as part of the Phase II work. The workplan document can be found as Attachment I to this questionnaire. The work plan document summarizes the background for developing the updated WRAP emissions inventory and details the methodology and approach that will be taken for each major category of pollutant that we will address. This updated inventory represents a Phase II emissions inventory and seeks to update and make improvements on the Phase I emissions inventory that was conducted previously. The Phase II inventory will rely on more detailed information from producers' on their activities in the WRAP region on a basin-wide average basis as well as information provided by the states.

SECTION 1

GENERAL QUESTIONS/COMMENTS

Please provide answers to general questions to ENVIRON by December 7, 2006.

Please provide an overview of your Oil and Gas operations in the WRAP region; identify the principal areas of operation and specifically in which basins you have production operations.

In responding to the questions below, please indicate the following for all information that you provide to us:

- **Field, formation or basin to which your information refers**
- **Whether the well, field, formation or basin has conventional or CBM production**
- **Whether the well, field, formation or basin is electrified**
- **Whether the well, field, formation or basin has significant sour gas (H_2S) production**

Please respond to all questions with information from calendar year 2002.

DRILLING RIG EMISSIONS

Please provide answers to questions on Drilling Rig Emissions by December 7, 2006.

1. What are the actual average drilling times (beginning and completion dates) for your drilling operations by formation and by basin in which the formation is located? Please provide either detailed information on drilling times by well, or an average by formation or basin.
2. What are the average drilling depths for your drilling operations by formation and by basin in which the formation is located? Please provide either detailed information on drilling depths by well, or an average by formation or basin.
3. What is the actual load on the drilling rig engine for each well? If this is unavailable, please provide an estimate of the average load of drilling rig engines operating within a formation, or within a basin. Please identify if this load is significantly different if the well is a new well or a workover.
4. What is the average horsepower of drilling rig engines used in your operations in each formation within a basin, or as a basin-wide average? Please identify if the average horsepower of drilling rig engines is significantly different if the well is a new well or a workover.
5. What is the most commonly used make and model (or up to 3 most commonly used makes and models) of drilling rig engines, grouped by horsepower, for each formation or basin in which you drill?
6. What are the manufacturers' rated emissions factors (EFs) for the drilling rig engines identified in Question 5? This should include NOx, CO, VOC, SOx and PM emissions.
7. What type of diesel fuel is used and what is the sulfur content of that diesel fuel for each drilling rig engine by formation, or by basin, or by county, or by state (as appropriate)?

Overview

The work plan addresses six categories of emissions: drilling rigs; compressor engines; CBM engines; VOC emissions from completion activities, venting and flashing; heaters; and fugitive dust. Except where noted, emissions will be estimated on a count basis, rather than a production basis. This reflects the expected availability of detailed information from producers on their activities in the WRAP region. Count-based data will be averaged within each major basin of significant O & G activity in the WRAP region.

This questionnaire is organized into two sections:

1. Section 1 contains the detailed questions for producers by emissions category
2. Section 2 contains a brief checklist for producers to indicate whether or not the information in Section 1 is available. Section 2 can also be used as a quick reference guide for the information we are requesting.

Where possible, detailed information is requested and it is preferable that this information be provided in electronic form. The information requested for drill rigs and compressor engines, as well as the general questions and questions on projections, are the most important. In order to meet our schedule for completing the WRAP emissions estimates, the deadlines for receiving information are:

1. General questions and questions on drilling rig engines - December 7, 2006
2. Questions on compressor engines and 2018 emissions projections - December 22, 2006
3. All other information - January 10, 2006

We would like to encourage producers to provide information as soon as possible so that we will have sufficient time to conduct a thorough analysis incorporating this information. We are requesting a brief response by November 28, 2006 with whether or not you will be able to provide information on the specific questions included in this questionnaire. Please use the checklist in Section 2 to indicate the availability of information on your operations. Prompt notice of how much data we can or cannot expect in advance of the actual deadline for data transfer will help ensure the best possible analysis is conducted.

ENVIRON will hold confidential all information provided by producers; we will not share specific producer information in response to the operations. We will use the information provided to aggregate and report emissions by field, formation or basin.

All information should be provided in electronic format if possible and preferably in spreadsheet format. All data should be returned to:

Amnon Bar-Ilan
ENVIRON Corporation
101 Rowland Way, Suite 220
Novato, CA 94945
Tel. (415) 899-0732 Fax. (415) 899-0707
Email: abarilan@environcorp.com

If you have any questions regarding this questionnaire, or any of the questions contained here, please feel free to contact Mr. Bar-Ilan at the phone number or email address above.

8. Please provide, if possible, information on the total fuel consumption, or fuel consumption rate of drilling rig engines that you operate.
9. What percentage of drilling rig engines in each basin in which you operate use air-assist packages?
10. For those drilling rig engines with air-assist packages identified in Question 9, what is the most commonly used make and model of air compressor used in the air-assist package? What is the average load of that compressor, and what are the manufacturers' rated EFs for that compressor?

COMPRESSOR ENGINE EMISSIONS

Please provide answers to questions on Compressor Engine Emissions by December 22, 2006.

1. How many wells do you operate within each basin in which you operate? Please indicate number of wells and in which basin these wells are located.
2. What fraction of the number of wells in each basin in which you operate use wellhead compressors, what fraction use lateral compressors, and what fraction use centralized compressors? If this information is not available as a fraction of the number of wells, is this information available as a fraction of the total horsepower of compression in each basin in which you operate? If so, please provide the information as a fraction of total horsepower of compression in each basin.
3. What is the average load on a wellhead and/or lateral compressor engine as a basin-wide average for each basin in which you operate?
4. What are the 3 most commonly used makes and models of wellhead and/or lateral compressors in each basin in which you operate?
5. What are the manufacturers' rated emissions factors of NOx, CO, and VOC for each of the makes and models of compressor engines identified in Question 4?

VOC EMISSIONS

Please provide answers to questions on VOC Emissions by January 10, 2007.

Venting of wells occurs frequently to unload fluids that may after time reduce the amount of gas produced. How frequently do you vent wells, and what are the venting flow rates and the amount of time the wells were vented by formation or basin?

Have you taken any measures to reduce venting activity between 2002 and 2005? If so, what is the current frequency of venting at wells averaged by formation or basin?

For NMED, emissions from fugitives were estimated by defining a typical well setup for oil, conventional gas and CBM gas wells. The diagrams for these typical wells are shown in Attachment II of this document. Do these typical well setups adequately represent your operations?

If not, please provide as much detailed information as possible about your typical well setup, including number and type of each item of equipment typically used.

Do you use glycol dehydrators in the field for each basin in which you operate, or are they used only at large central gas plants? If you use glycol dehydrators in the field, please provide information on the number of these units in each basin in which you operate.

What are the emissions rates of your glycol dehydration units?

CBM ENGINE EMISSIONS

Please provide answers to questions on CBM Engine Emissions by January 10, 2007.

What fraction of wells in each basin you operate are CBM wells and what fraction are conventional wells?

For the basins in which you operate that have significant CBM activity, which fuel is used to power CBM engines?

What is the typical activity of the CBM engine (hours per year of operation)? Is the engine running continuously on an annual basis, or for how much time as a basin-wide average?

What is the water production rate from CBM wells that you operate as a basin-wide average?

What is the horsepower of CBM engines as a basin-wide average?

What is the average load of a CBM engine as a basin-wide average? If the CBM engine is fully loaded for a fraction of its total activity time, and lightly loaded as water production decreases, what are these two loads and what fraction of the total activity time is the CBM engine running in each of these modes?

What are the manufacturers' rated or tested EFs for a typical or most commonly used CBM engine?

Are there any emissions control technology installed on a CBM engine and if so what is the effectiveness of these controls for each pollutant (NOx, CO, VOC, SOx, PM)?

What is the fuel consumption rate of CBM engines as a basin-wide average?

HEATER EMISSIONS

Please provide answers to questions on Heater Emissions by January 10, 2007.

1. How many heaters are used at each well site as a basin-wide average for each basin in which you operate? What fraction of all wells within a basin use heaters (for each basin in which you operate)?
2. What is the fuel consumption rate of heaters in the basins in which you operate as a basin-wide average?
3. What is the heat content of the gas used in heaters in each basin in which you operate as a basin-wide average?
4. What is the annual usage of heaters in each basin in which you operate, as number of hours per month for each month? If heaters are operated for some wells in some basins only during winter months, please indicate this.
5. What are the manufacturers' rated EFs for a typical make and model of heater that you operate?
6. What is the sulfur content of the fuel with which the heater operates for each basin in which you operate as a basin-wide average?

FUGITIVE DUST EMISSIONS

Please provide answers to questions on Fugitive Dust Emissions by January 10, 2007.

ENVIRON may conduct an analysis to estimate fugitive dust emissions as part of the Phase II emissions inventory described above. Fugitive dust emissions are defined as re-entrained dust from unpaved roads leading to oil and gas well sites that are serviced by motor vehicles, as part of your O & G operations. Please answer the following questions about fugitive dust following the definition above:

1. Have you ever estimated or reported fugitive road dust emissions from your O & G operations in any basin or state in which you operate? If so, please provide this information.
2. Can you estimate the mileage of unpaved roads leading to well sites as part of your O & G operations in each basin and state? If so, please provide this information.
3. Can you estimate the total vehicle miles traveled (VMT) on unpaved roads leading to well sites of all vehicles that are part of your O & G operations in each basin and state? If so, please provide this information.
4. Can you estimate the average weekly or monthly number of trips on unpaved roads leading to each well site for your O & G operations, and the average miles per trip?
5. What are the typical types of vehicles that travel on unpaved roads to each of your well sites (i.e. van, pickup, truck, etc)?

2018 EMISSIONS PROJECTIONS

Please provide answers to questions on 2018 Emissions Projections by December 22, 2006.

1. For each basin in which you operate, what is the fraction of wells that have wellhead, lateral, and centralized compression for calendar years 2002 and 2005. Can you estimate these same fractions for year 2018 and any or all future years between 2005 and 2018? If this information is not available as a fraction of number of wells, is this information available as a fraction of the total horsepower in each basin in which you operate? If so, please provide this information.
2. What was the estimated average production per well as a basin-wide average in 2002? What was this production per well in 2005? What is the estimated future production per well in calendar year 2018? Please provide information for any future calendar year up to 2018 for which you have an estimate.

SECTION 2

Below is a brief checklist of the information requested in the Section 1 questions. We would like to know whether or not information on each emissions category is available before you begin to answer the questions and provide quantitative information. Please respond to the checklist below and check "Yes" or "No" to whether detailed information is available for each question in each emissions category. If some information is available but not all, please check "Yes". **Please return this completed checklist to ENVIRON by Tuesday, November 28th, 2006.**

Please note that item I – Drilling Rig Emissions, item II – Compressor Engine Emissions, and item VII – 2018 Emissions Projections are the highest priority emissions categories for purposes of this questionnaire. Please reply with information on these emissions categories as soon as possible. All other information may arrive afterwards, but no later than the January 10, 2007 deadline. The dates for specific categories are listed below.

I. Drilling Rig Emissions (due date: December 7, 2006)

	Yes	No
Drilling times		
Drilling depths		
Engine load		
Engine horsepower		
Engine makes/models		
Emissions factors		
Fuel type		
Fuel consumption rate		
Air-assist usage		
Air-assist compressors and compressor emissions factors		

II. Compressor Engine Emissions (due date: December 22, 2006)

	Yes	No
Number of wells by basin		
Fraction of wells with wellhead/lateral/centralized engines by basin		
Fraction of total compression HP that is wellhead/lateral/centralized by basin		
Average load on compressors by basin		
Average makes/models of compressors by basin		
Emissions factors		

III. VOC Emissions (January 10, 2006)

	Yes	No
Frequency of venting at wells		
Venting flow rates		
Venting times		
Recent changes in venting frequency		
Typical well setups		
Glycol dehydrator usage		
Glycol dehydrator emissions rates		

IV. CBM Engine Emissions (due date: January 10, 2006)

	Yes	No
Fraction of CBM wells/conventional wells in each basin		
CBM engine fuel		
CBM engine activity		
Water production rates		
Average horsepower of CBM engines		
Average load of CBM engines		
Emissions factors		
Emissions control technology		
Fuel consumption rate		

V. Heaters (due date: January 10, 2006)

	Yes	No
Number of heaters per well		
Fraction of wells with heaters		
Average fuel consumption rate		
Average heat content of heater fuel		
Annual or monthly activity of heaters		
Emissions factors		
Sulfur content of heater fuel		

VI. Fugitive Dust Emissions (due date: January 10, 2006)

	Yes	No
Estimates or reports on fugitive dust from your operations		
Mileage of unpaved roads leading to well sites		
VMT of vehicles traveling on unpaved roads to well sites		
Average weekly or monthly number of trips to well sites		
Types of vehicles traveling on unpaved roads to well sites		

VII. 2018 Emissions Projections (due date: December 22, 2006)

	Yes	No
Fraction of wells by basin with wellhead/lateral/central compression in 2002		
Fraction of wells by basin with wellhead/lateral/central compression in 2005		
Estimate of fraction of wells with wellhead/lateral/central compression for any calendar year between 2005 and 2018		
Production per well by basin for 2002		
Production per well by basin for 2005		
Estimate of production per well by basin for any calendar year between 2005 and 2018		

EXHIBIT 5

Memo from Richard R. Long, Region VIII Dir., Air and Radiation Program to Lynn Menlove, Manager, New Source Review Section, Utah Division of Air Quality (May 21, 1998)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

May 21, 1998

Ref: 8P2-A

Lynn Menlove, Manager
New Source Review Section
Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Re: Response to Request for Guidance in Defining Adjacent with Respect to Source Aggregation

Dear Mr. Menlove:

This is in response to your letter of January 15, 1998, to Mike Owens of my staff, requesting guidance and/or specific recommendations in the matter of Utility Trailer Manufacturing Company. For the purpose of determining if two Utility Trailer facilities should or should not be aggregated into a single source under Clean Air Act Title V and New Source Review permitting programs, you asked what is the specific physical distance associated with the definition of "adjacent." The word "adjacent" is part of the definition of "source" in the Utah SIP regulations, at R307-1-1. The SIP definition follows the Federal definition found in 40 CFR 51.166.

In brief, our answer is that the distance associated with "adjacent" must be considered on a case-by-case basis. This is explained in the preamble to the August 7, 1980 PSD rules, which says "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." After searching the New Source Review Guidance Notebook, and after querying the other Regions and EPA's Office of Air Quality Planning and Standards, we have found no evidence that any EPA office has ever attempted to indicate a specific distance for "adjacent" on anything other than a case-by-case basis. We could not find any previous EPA determination for any case that is precisely like Utility Trailer, i.e., two facilities under common control, with the same primary 2-digit SIC code, located about a mile apart, both producing very similar products, but claimed by the company to be independent production lines.

Utah SIP regulations do not define "adjacent." The definition in the 1995 edition of Webster's New College Dictionary is: 1. Close to; nearby, or 2. Next to; adjoining. We realize this leaves considerable gray area for interpretation; however, since the term "adjacent" appears in the Utah SIP as part of the definition of "source," any evaluation of what is "adjacent" must relate to the guiding principle of a common sense notion of "source." (The phrase "common sense notion" appears on page 52695 of the August 7, 1980 PSD preamble, with regard to how to define "source.") Hence, a determination of "adjacent" should include an evaluation of whether the distance between two facilities is sufficiently small that it enables them to operate as a single "source." Below are some types of questions that might be posed in this evaluation, as it pertains to Utility Trailer. Not all the answers to these questions need be positive for two facilities to be considered adjacent.

-- 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? Supporting evidence for this could include a physical link or transportation link between the facilities, such as a pipeline, railway, special-purpose or public road, channel or conduit.

-- Will managers or other workers frequently shuttle back and forth to be involved actively in both facilities? Besides production line staff, this might include maintenance and repair crews, or security or administrative personnel.

-- 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? For example, will components be assembled at one facility but painted at the other?

One illustration of this type of evaluation involved Great Salt Lake Minerals in Utah, which we wrote to you about on August 8, 1997, in response to your inquiry. (See enclosure #1.) We recommended, as EPA guidance, that you treat the two GSLM facilities as a single source (i.e., "adjacent"), despite the fact that they are a considerable distance apart (21.5 miles). We based that advice on the functional inter-relationship of the facilities, evidenced in part by a dedicated channel between them. We wrote that the lengthy distance between the facilities "is not an overriding factor that would prevent them from being considered a single source."

Another illustration is ESCO Corporation in Portland, Oregon, which operates two metal casting foundries (a "Main Plant" and a "Plant 3"), a couple of blocks apart. All castings produced by foundries at both facilities are coated, packaged and shipped at the "Main Plant". EPA Region 10 wrote to the State of Oregon on August 7, 1997 (see enclosure #2), that the guiding principle in evaluating whether the two facilities are "adjacent" is "the common sense notion of a plant. That is, pollutant emitting activities that comprise or support the primary product or activity of a company or operation must be considered part of the same stationary source." EPA determined that the two ESCO facilities must be considered a single major stationary source, since they function together in that manner, even though the Plant 3 foundry operates independently from the Main Plant foundry.

Another illustration is Anheuser-Busch in Fort Collins, Colorado, which operates a brewery and landfarm about six miles apart. A memo from OAQPS to our Regional Office, dated August 27, 1996 (see enclosure #3), stated that with regard to "contiguous or adjacent," the facilities should be treated as one source, due to their functional inter-relationship (landfarm as an integral part of the brewery operations), evidenced in part by a disposal pipeline between them. The fact that they are a considerable distance apart "does not support a PSD determination that the brewery proper and the landfarm constitute separate sources for PSD purposes."

Another illustration is Acme Steel Company, which operates an integrated steel mill consisting of coke ovens and blast furnaces at a site in Chicago, Illinois, along with basic oxygen furnaces, casting and hot strip mill operations at a site in Riverdale, Illinois, about 3.7 miles away. The blast furnace in Chicago produces hot metal that is transported via commercial rail to the BOF shop in Riverdale for further processing into steel. EPA Region 5 wrote to the State of Illinois on March 13, 1998 (see enclosure #4), that "Although the two sites are separated by Lake Calumet, landfills, I-94, and the Little Calumet River, USEPA considers that the close proximity of the sites, along with the interdependency of the operations and their historical operation as one source, as sufficient reasons to group these two facilities as one."

Therefore, in the matter of Utility Trailer, we recommend you evaluate, using questions such as those we posed above, whether the two facilities (one existing and one proposed for construction) will, in fact, operate independently of each other, as the company has claimed. Athough Utility Trailer writes that "The present facility is not capable of conversion to the new trailer manufacturing process," they also write that the existing facility is "an inefficient manufacturing process which has made this facility less cost-competitive." This suggests to us the possibility that the existing facility could become a support facility for the new one. The company should be advised that if the two facilities are later discovered by the State and/or EPA to be actually operating as a single major source, and no Title V or PSD permit applications have been submitted where required by regulation, the company could become subject to State or EPA enforcement action or citizen suit.

Finally, please be aware that if the facilities are treated as two separate sources, no emission netting between them can be allowed, to avoid major source NSR permitting at either facility, in the event of future facility modifications.

We hope this letter will be helpful. It has been written only as guidance, as it remains the State's responsibility to make source aggregation determinations under EPA-approved State programs and regulations. This letter has been reviewed by specialists at OAQPS, by our Office of Regional Counsel, and by Office of General Counsel at EPA Headquarters. We apologize for the delay in getting our response to you.

If you have questions, please contact Mike Owens. He is at at (206) 553-6511 until late June, after which he may be reached at (303) 312-6440.

Sincerely,

Richard R. Long
Director
Air Program

Enclosures (4)

cc: Rick Sprott, Utah DAQ
Scott Manzano, Utah DAQ
Jose Garcia, Utah DAQ

EXHIBIT 6

Draft Title V Permit for the Wolf Point Compressor Station,
Permit Number V-SU-0034-07.00

United States Environmental Protection Agency
Region VIII
Air Program
1595 Wynkoop Street
Denver, Colorado 80202

AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

In accordance with the provisions of title V of the Clean Air Act and 40 CFR part 71 and applicable rules and regulations,

BP America Production Company
Wolf Point Compressor Station

is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the permit conditions listed in this permit.

This source is authorized to operate at the following location:

Southern Ute Indian Reservation
NW ¼ Section 16, T33N, R9W
La Plata County, Colorado

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations. All terms and conditions of the permit are enforceable by EPA and citizens under the Clean Air Act.

______________________________ ______________________

Callie A. Videtich, Director
Air Program
US EPA Region VIII

Date

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AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE
BP America Production Company
Wolf Point Compressor Station

Permit Number: V-SU-0034-07.00
Replaces Amended Permit No.: V-SU-0034-02.04

Issue Date:
Effective Date:
Expiration Date:

The permit number cited above should be referenced in future correspondence regarding this facility.

<u>Permit Revision History</u>

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION
February 2003	Initial Permit Issued		Title V Permit #V-SU-0034-02.00
TBD	1st Renewal Permit Issued		Title V Permit #V-SU-0034-07.00

TABLE OF CONTENTS

Abbreviations and Acronyms

AR	Acid Rain
ARP	Acid Rain Program
bbls	Barrels
BACT	Best Available Control Technology
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CMS	Continuous Monitoring System (includes COMS, CEMS and diluent monitoring)
COMS	Continuous Opacity Monitoring System
CO	Carbon monoxide
CO2	Carbon dioxide
DAHS	Data Acquisition and Handling System
dscf	Dry standard cubic foot
dscm	Dry standard cubic meter
EIP	Economic Incentives Programs
EPA	Environmental Protection Agency
FGD	Flue gas desulfurization
gal	Gallon
GPM	Gallons per minute
H2S	Hydrogen sulfide
gal	gallon
HAP	Hazardous Air Pollutant
hr	Hour
Id. No.	Identification Number
kg	Kilogram
lb	Pound
MACT	Maximum Achievable Control Technology
MVAC	Motor Vehicle Air Conditioner
Mg	Megagram
MMBtu	Million British Thermal Units
mo	Month
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMHC	Non-methane hydrocarbons
NOx	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
pH	Negative logarithm of effective hydrogen ion concentration (acidity)
PM	Particulate Matter
PM_{10}	Particulate matter less than 10 microns in diameter
ppm	Parts per million
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
psi	Pounds per square inch
psia	Pounds per square inch absolute
RICE	Reciprocating Internal Combustion Engine
RMP	Risk Management Plan
scfm	Standard cubic feet per minute
SNAP	Significant New Alternatives Program
SO_2	Sulfur Dioxide
tpy	Ton Per Year
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

LIST OF TABLES

I. Source Information and Emission Unit Identification

I.A. Source Information

Parent Company Name: BP America Production Company

Plant Name: Wolf Point Compressor Station

Plant Location: NW ¼ Section 16, T33N, R9W
Latitude: 37.10743378 Longitude: -107.8353513

Region: VIII

State: Colorado

County: La Plata

Reservation: Southern Ute Indian Reservation

Tribe: Southern Ute Indian Tribe

Responsible Official: Florida Operations Manager

SIC Code: 1311

AFS Number: 08-067-00360

Other Clean Air Act Permits: This is the first renewal of the part 71 permit. There are no other Federal CAA permits, such as PSD or minor NSR, issued to this facility.

Description of Process:

BP America Production Company owns and operates the Wolf Point Compressor Facility. Fruitland coal bed methane wells feed into a gathering pipeline system leading to this facility. The natural gas produced from these wells contains approximately 93% methane and 7% carbon dioxide and is water vapor saturated. The wells do not produce any condensate or natural gas liquids.

Upon entering the compressor station, the gas first passes through an inlet separator vessel to remove any free liquids in the gas stream by gravity. The gas then passes to a filter vessel, which serves to filter out any solids such as coal dust in the gas. The gas is then compressed and finally passes through an outlet coalescer vessel which removes any entrained droplets of lubricating oil before being metered and sent to the BP Florida River Compressor Facility for further processing. In addition, there are no pigging facilities or operations associated with this station.

Description of Phased Engine Replacement Project:

BP plans to conduct a compressor engine replacement project that will be phased to avoid major status for emissions of hazardous air pollutants (HAP) and to avoid triggering applicability to requirements for major sources of HAPs. BP will be replacing the four existing Waukesha L7042GL compressor engines with three Caterpillar G3606 compressor engines operating with federally enforceable oxidation catalyst controls and emission limits. The replacement project is anticipated to begin in 2008, with operation in later 2008 or early 2009. Concurrent with installation of the replacement engines, the existing engines will be removed from service.

Under current operations, the facility is a major source of HAP emissions, because the four existing Waukesha engines have a potential to emit (PTE) formaldehyde greater than 10 tons per year (tpy). Current operations have not, however, triggered requirements of the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, Maximum Achievable Control Technology (RICE MACT, 40 CFR part 63, subpart ZZZZ) or the New Source Performance Standards for Spark Ignition Internal Combustion Engines (SI NSPS), because the current configuration of engines is "existing" 4 stroke lean burn (4SLB) engines per 40 CFR §§60.2, 60.4230, 63.2 and 63.6590. Because these engines are existing per the definitions in the RICE MACT and SI NSPS, they are therefore not subject to any of the associated requirements. In order to maintain the facility's status for non-applicability to the major source requirements of the RICE MACT, the engines will be replaced in phases according to the Alternative Operating Scenarios in **Table 1** below, each of which will reduce (Scenarios #1a-c and #2) and maintain (Scenario #3) the maximum PTE of formaldehyde below the HAP major source threshold of 10 tons per year (tpy) throughout the replacement project. For the first phase of the project, BP may operate the facility under any one of Alternative Operating Scenarios #1a, #1b, #1c, or #2. BP would then operate the facility under Alternative Operating Scenario #3 for the second and final phase of the project.

Table 1 – Potential Facility Operating Scenarios

Operating Scenario	**Emission Units Operating**
Current Operating Scenario	C1, C2 , C3, C4, G1
Alternative Operating Scenarios #1a - #1c	C1 (#1a) <u>or</u> C2(#1b) <u>or</u> C3 (#1c), G1, WP1, WP2
Alternative Operating Scenario #2	C4, G1, WP1, WP2
Alternative Operating Scenario #3	G1, WP1, WP2, WP3

Because the replacement RICE compressor engines will require controls for emissions of carbon monoxide and formaldehyde to comply with the requested synthetic minor emission status, specific emission limits and other requirements for the Caterpillar compressor engines (WP1, WP2, and WP3) are described in sections **II.** and **III.**, dependent on the scenario under which the facility is operating at that given time.

I.B. Source Emission Points

Table 2 - Emission Units – Current Operating Scenario
BP Wolf Point Compressor Station

Emission Unit ID	Description	Control Equipment
	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engines	None
C1	Serial No. 316401 Rebuilt*/Installed: 4/15/06 (constructed 12/20/1977)	
C2	Serial No. C61492/1 Rebuilt*/Installed: 5/19/06 (constructed 12/11/1998)	
C3	Serial No. 296963 Installed: 2001	
	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engine	Oxidation Catalyst controller (not federally enforceable)
C4	Serial No. 351077 Rebuilt*/Installed: 9/11/2007 (constructed 2001 at BP Red Willow)	
	59 hp, lean burn, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	None
G1	Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	

*The term "rebuilt" is not to be confused with the term "reconstruction", as defined in 40 CFR 63.2. According to BP, these engines have previously operated at other facilities and have been modified for a cost less than 50% of the cost to purchase a new engine, and are therefore, not considered "reconstructed" after 12/19/2002 and thus not subject to 40 CFR part 63, subpart ZZZZ.

Table 3 - Emission Units – Alternative Operating Scenarios #1a - #1c

BP Wolf Point Compressor Station

Emission Unit ID	Description	Control Equipment
	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engines	None
C1 (scenario #1a) or C2 (scenario #1b) or C3 (scenario #1c)	Serial No. 316401 Rebuilt*/Installed: 4/15/06 (constructed 12/20/1977) Serial No. C61492/1 Rebuilt*/Installed: 5/19/06 (constructed 12/11/1998) Serial No. 296963 Installed: 2001	
	1895 hp, lean burn, natural gas-fired Caterpillar G3606 Compressor Engines (either 90°F or 129°F Engine Control Modules (ECM))	Oxidation Catalyst controllers
WP1 WP2	Serial No. TBD Projected Installation: 2008/2009 Serial No. TBD Projected Installation: 2008/2009	
	59 hp, lean burn, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	None
G1	Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	

*The term "rebuilt" is not to be confused with the term "reconstruction", as defined in 40 CFR 63.2. According to BP, these engines have previously operated at other facilities and have been modified for a cost less than 50% of the cost to purchase a new engine, and are therefore not considered "reconstructed" after 6/12/2006 and thus not subject to 40 CFR part 60, subpart JJJJ or part 63, subpart ZZZZ.

Table 4 - Emission Units – Alternative Operating Scenario #2
BP Wolf Point Compressor Station

Emission Unit ID	Description	Control Equipment
C4	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engines Serial No. 351077 Rebuilt*/Installed: 9/11/2007 (constructed 2001 at BP Red Willow)	Oxidation Catalyst controller (not federally enforceable)
WP1 WP2	1895 hp, lean burn, natural gas-fired Caterpillar G3606 Compressor Engines (either 90°F or 129°F ECM) Serial No. TBD Projected Installation: 2008/2009 Serial No. TBD Projected Installation: 2008/2009	Oxidation Catalyst controllers
G1	59 hp, lean burn, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine) Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	None

*The term "rebuilt" is not to be confused with the term "reconstruction", as defined in 40 CFR 63.2. According to BP, this engine has previously operated atanother facilityand has been modified for a cost less than 50% of the cost to purchase a new engine, and is, therefore, not considered "reconstructed" after 12/19/2002 and thus not subject to 40 CFR part 60, subpart JJJJ or part 63, subpart ZZZZ.

Table 5 - Emission Units – Proposed Alternative Operating Scenario #3 Equipment
BP Wolf Point Compressor Station

Emission Unit ID	Description	Control Equipment
WP1 WP2 WP3	1895 hp, lean burn, natural gas-fired Caterpillar G3606 Compressor Engines (either 90°F or 129°F ECM) Serial No. TBD Projected Installation: 2008/2009 Serial No. TBD Projected Installation: 2008/2009 Serial No. TBD Projected Installation: 2008/2009	Oxidation Catalyst controllers
G1	59 hp, lean burn, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine) Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	None

Table 6 - Insignificant Emission Units (All Operating Scenarios)
BP Wolf Point Compressor Station

Emission Unit ID	Description
1	Process Fugitive Emissions
2	Compressor Blowdowns, max of 395 MMscf/yr
3	4 - 500 gallon (or one 2,000 gallon) Used Oil Tanks
4	4 - 500 gallon (or one 2,000 gallon) Lube Oil Tanks
5	1 - 300 bbl Produced Water Tank
6	1 - 0.5 MMBtu/hr heater for the produced water tank
7	1 - 300 bbl Produced Water/Oily Water Tank
8	1 - 0.5 MMBtu/hr heater for the produced water/oily water tank
9	2 – 286 bbl Water Tanks
10	2 – 0.5 MMBtu/hr Heater for the water tanks
11	1 – 575 gallon TEG Tank
12	1 – 0.25 MMBtu/hr Dehy Reboiler
13	1 - 2.0 MMscfd Glycol Still Column Vent
14	1 - 750 gallon Ethylene Glycol Tank
15	1 – 21 bbl Lube Oil Drip Tank

I.C. Changes in Facility Operating Scenario
[40 CFR 71.7(e)(1), 71.6(a)(12) and (13), and 71.6(a)(3)(ii)]

1. In accordance with Off Permit Changes condition **V.Q.4.** of this permit, the permittee shall provide contemporaneous written notice to EPA prior to installation of the replacement engines that would constitute each change in the specific facility operating scenarios described in Sections **I.A.** and **I.B.** above.

2. For replacement engines which trigger new applicable requirements (i.e., NSPS, NESHAP, etc.), the minor permit modification process (condition **V.I.** of this permit) shall be utilized to maintain the permitted emission limits of the replaced engine and incorporate the new applicable requirements.

3. Upon completion of the final phase of the engine replacement project, described in Section **I.A.** above, the permittee shall use the minor permit modification process (condition **V.I.** of this

permit) to establish Alternative Operating Scenario #3, including its associated emission limits and other specific requirements, as the permanent permitted operating scenario for the facility. Installation of any additional insignificant emission units resulting from the engine replacement project shall be addressed as part of the same minor permit modification.

II. Specific Requirements for Alternative Operating Scenarios #1a, #1b,#1c and #2

Requirements in this section of the permit have been created, at the permittee's request, to recognize emissions control equipment on engine units WP1 and WP2 for limiting the PTE of carbon monoxide (CO), and formaldehyde (CH_2O).

[CAA 304(f)(4), 40 CFR 71.6(b) and 71.7(e)(1)(i)(A)(4)(i)]

II.A Limitations on Use [40 CFR 71.7(e)(1), 71.6(a)(12) and (13), and 71.6(a)(3)(ii)]

If any of the engine replacement alternative operating scenarios #1a, #1b, #1c, or #2, trigger applicability to new requirements that are not described in this section, then use of the Alternative Operating Scenario shall not be allowed. If a change would trigger applicability to new requirements, the permittee shall make the change using the minor permit modification process (condition **V.I.** of this permit).

II.B. Emission Limits

Emissions from engine units WP1 and WP2 equipped with oxidation catalysts shall not exceed:

1. 1.04 pounds per hour of carbon monoxide (CO) emissions; and

2. 0.67 pounds per hour of formaldehyde (CH_2O) emissions.

II.C. Work Practice and Operational Requirements

1. Units WP1and WP2 are Caterpillar G3606 lean burn natural gas compressor engines each with a maximum rating of 1,895 brake horsepower (bhp). Each engine shall be equipped with an oxidation catalyst control system capable of reducing uncontrolled emissions of CO and CH_20 at maximum operating rate (90% to 110% of engine capacity) to achieve the emission limits in section **II.B.**

2. The permittee shall follow, for each engine and its respective catalyst, the manufacturer's recommended maintenance schedule and procedures to ensure optimum performance of each engine and catalyst.

3. All emission units at the Wolf Point Compressor Station shall be fired only with natural gas. The natural gas shall be pipeline-quality in all respects except that CO_2 concentration in the gas shall not be required to be within pipeline-quality.

   [The purpose of this permit condition is to ensure there are no contaminants in the fuel that might foul the catalyst. CO_2 is not a potential foulant of the catalyst.]

4. The permittee shall install temperature-sensing devices before the oxidation catalyst for units WP1 and WP2 in order to monitor the inlet temperatures of the catalyst for each engine. Each temperature-sensing device shall be accurate to within 0.75% of span.

5. The engine exhaust temperature for units WP1 and WP2 at the inlet to the oxidation catalyst, shall be maintained at all times the engines operate at no less than 450°F and no more than 1350°F.

6. If the catalyst inlet temperature on any engine deviates from the acceptable range listed for each engine in section **II.C.5** above, then the following actions shall be taken:

   (a) Immediately upon determining a deviation of the catalyst inlet temperature, corrective action shall be taken on that engine to assess performance problems and/or tuning issues and the oxidation catalyst shall be inspected for possible damage and problems affecting catalyst effectiveness (including, but not limited to, plugging, fouling, destruction, or poisoning of the catalyst).

   (b) If the problem can be corrected by following the engine and/or the oxidation catalyst manufacturer's recommended procedures, then the permittee shall correct the problem within 24 hours of inspecting the engine and oxidation catalyst.

   (c) If the problem can not be corrected using the manufacturer's recommended procedures, then the affected engine shall cease operating immediately and shall not be returned to routine service until the catalyst inlet temperature is measured and found to be within the acceptable temperature range for that engine. The permittee shall also notify EPA in writing of the problem within 15 working days of observing the problem and include in the notification the cause of the problem and a corrective action plan that outlines the steps and timeframe for bringing the inlet temperature range into compliance. (the corrective action may include removal and cleaning of the oxidation catalyst according to the *manufacturer's methods or replacement of the oxidation catalyst.)*

7. The permittee shall utilize pressure measuring technology on units WP1 and WP2 in order to monitor pressure drop across the catalyst.

8. The pressure drop across the catalyst for units WP1 and WP2 shall not change by more than two (2) inches of water at 100% load plus or minus 10% from the baseline pressure drop across the catalyst measured during the initial performance test. *[Comment: Pressure drop is a good indication of catalyst operation; too low, the catalyst may be blown out; too high, it may be clogged].*

9. If the pressure drop exceeds two (2) inches of water from the baseline pressure drop reading taken during the initial performance test, the cause will be investigated. Investigation may include monitoring CO emissions to ensure the oxidation catalyst is functioning and testing the pressure transducers. If the cause is determined to be the catalyst, then the catalyst shall be inspected and cleaned or replaced, if necessary.

10. *The permittee's completion of any or all of the actions prescribed by conditions* ***II.C.6(a)*** through **(c)** and **II.C.9** of this permit shall not constitute, nor qualify as, an exemption from any CO and CH_2O emission limits in this permit.

II.D. Testing Requirements [40 CFR 71.6(a)(3)(i)(A) through (C)]

1. An initial performance test shall be conducted for engine units WP1 and WP2 for measuring CO and CH_2O emissions from the engines to demonstrate initial compliance with the emission limits in section **II.B**. The initial performance tests shall be conducted within ninety (90) calendar days of startup of WP1 and WP2.

2. Upon change out of the catalyst for engine units WP1 and WP2, a performance test shall be conducted for measuring CO and CH_2O emissions from the engines to demonstrate compliance with the emission limits in section **II.B** and re-establish temperature and pressure correlations. The performance test shall be conducted within ninety (90) calendar days of the catalyst change out.

3. The performance test for CO shall be conducted in accordance with the test methods specified in 40 CFR part 60, appendix A. EPA Reference Method 10 shall be used to measure CO emissions.

4. The performance test for CH_2O shall be conducted in accordance with the test methods specified in 40 CFR part 63, appendix A. EPA Reference Method 320 or 323 shall be used to measure CH_2O emissions.

5. All tests for CO and CH_2O emissions must meet the following requirements:

   (a) All tests shall be performed at a maximum operating rate (90% to 110% of engine capacity).

   (b) During each test run, data shall be collected on all parameters necessary to document how CO and CH_2O emissions in pounds per hour were measured or calculated (such as test run length, minimum sample volume, volumetric flow rate, moisture and oxygen corrections, etc.). The temperature at the inlet to the catalyst and the pressure drop across the catalyst shall also be measured and recorded during each test run for each engine.

   (c) Each source test shall consist of at least three (3) 1-hour or longer valid test runs. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of the emission limits (pounds per hour and grams per horsepower-hour).

   (d) A source test plan for engine units WP1 and WP2 for CO and CH_2O emissions shall be submitted to EPA for approval at least forty five (45) calendar days prior to the scheduled performance test.

   (e) The source test plan shall include and address the following elements:

      (i) Purpose of the test;
      (ii) Engines and catalysts to be tested;
      (iii) Expected engine operating rate(s) during test;

(iv) Schedule/dates for test;
(v) Sampling and analysis procedures (sampling locations, test methods, laboratory identification);
(vi) Quality assurance plan (calibration procedures and frequency, sample recovery and field documentation, chain of custody procedures); and
(vii) Data processing and reporting (description of data handling and quality control procedures, report content).

II.E. Monitoring Requirements [40 CFR 71.6(a)(3)(i)(A) through (C)]

1. The permittee shall measure CO emissions from units WP1 and WP2 at least semi-annually or once every six (6) month period to demonstrate compliance with the emission limits in section **II.B** above. The two six month periods are January 1st through June 30th and July 1st through December 31st. To meet this requirement, the permittee shall measure CO emissions from the engine unit using a portable analyzer and a monitoring protocol approved by EPA. The permittee shall submit the analyzer specifications and monitoring protocol to EPA for approval within forty-five (45) calendar days of the start-up WP1 or WP2. Monitoring for CO emissions shall commence during the first complete calendar quarter following the permittee's submittal of the initial performance test results for CO to EPA.

2. The permittee shall measure CH_2O emissions from units WP1 and WP2 at least annually or once per calendar year to demonstrate compliance with the emission limits in section **II.B** above. To meet this requirement, the permittee shall measure CH_2O emissions from the engine using the performance test methods and requirements listed in section **II.D** above and the test plan approved by EPA as required in section **II.D.5(d)**. Monitoring for CH_2O emissions shall commence no sooner than the second calendar quarter after the permittee's submittal of the initial compliance test results for CH_2O to EPA.

3. The engine exhaust temperature at the inlet to the oxidation catalyst shall be measured at least **once per week**. Each temperature-sensing device shall be accurate to within 0.75% of span.

4. The pressure drop across the oxidation catalyst shall be measured **monthly**. The pressure sensing devices shall be accurate to within plus or minus one tenth (0.1) inches of water.

II.F. Recordkeeping Requirements [40 CFR 71.6(a)(3)(ii)]

1. The permittee shall comply with the following recordkeeping requirements:

(a) Records shall be kept of all temperature and pressure measurements required by this permit.
(b) Records shall be kept of vendor specifications for the temperature-sensing devices and pressure gauges.
(c) Records shall be kept of vendor specifications for the oxidation catalyst on WP1 and WP2.
(d) Records shall be kept that are sufficient to demonstrate, pursuant to condition **II.C.3** of this permit, that the fuel for the engines is pipeline-quality natural gas in all respects, with the exception of CO_2 concentration in the natural gas.

2. The permittee shall keep records of all required testing (section **II.D**) and monitoring (section **II.E**) in this permit. The records shall include the following:

(a) The date, place, and time of sampling or measurements;

(b) The date(s) analyses were performed;

(c) The company or entity that performed the analyses;

(d) The analytical techniques or methods used;

(e) The results of such analyses or measurements; and

(f) The operating conditions as existing at the time of sampling or measurement.

3. Records shall be kept of off-permit changes, as required by condition **V.Q** of this permit.

4. The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. These records shall be made available upon request by EPA. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

II.G. Reporting Requirements [40 CFR 71.6(a)(3)(iii)]

1. The permittee shall submit to EPA a written report of the results of the performance tests required in condition **II.D.** of this permit. This report shall be submitted within sixty (60) calendar days of the date of testing completion.

2. The permittee shall submit to EPA, as part of the semi-annual monitoring reports required by condition **IV.B** of this permit, a report of any instances where the temperature at the inlet to the catalyst is outside the limits established in condition **II.B.**, where the pressure drop across the catalyst is outside the limits established in the initial performance testing, or where an excursion of the CO or CH_2O emission limits has occurred, as well as a description of any corrective actions taken. If no such instances have been detected, then a statement shall be provided to say so.

III. Specific Requirements for Alternative Operating Scenario #3

Requirements in this section of the permit have been created, at the permittee's request, to recognize emissions control equipment on engine units WP1, WP2, and WP3 for limiting the PTE of carbon monoxide (CO), and formaldehyde (CH_2O).

[CAA 304(f)(4), 40 CFR 71.6(b) and 71.7(e)(1)(i)(A)(4)(i)]

III.A. Limitations on Use [40 CFR 71.7(e)(1), 71.6(a)(12) and (13), and 71.6(a)(3)(ii)]

If Alternative Operating Scenario #3 triggers applicability to new requirements that are not described in this section, then use of the Alternative Operating Scenario shall not be allowed. If the change would trigger applicability to new requirements, the permittee shall make the change using the minor permit modification process (condition **V.I.** of this permit).

III.B. Emission Limits

Emissions from engine units WP1, WP2, WP3 equipped with oxidation catalysts shall not exceed:

1. 1.04 pounds per hour of carbon monoxide (CO) emissions; and

2. 0.67 pounds per hour of formaldehyde (CH_2O) emissions.

III.C. Work Practice and Operational Requirements

1. Units WP1, WP2, and WP3 are Caterpillar G3606 lean burn natural gas compressor engines each with a maximum rating of 1,895 brake horsepower (bhp). Each engine shall be equipped with an oxidation catalyst control system capable of reducing uncontrolled emissions of CO and CH_2O emissions at maximum operating rate (90% to 110% of engine capacity) to achieve the emission limits in section **III.B**.

2. The permittee shall follow, for each engine and its respective catalyst, the manufacturer's recommended maintenance schedule and procedures to ensure optimum performance of each engine and catalyst.

3. All emission units at the Wolf Point Compressor Station shall be fired only with natural gas. The natural gas shall be pipeline-quality in all respects except that CO_2 concentration in the gas shall not be required to be within pipeline-quality.

   [The purpose of this permit condition is to ensure there are no contaminants in the fuel that might foul the catalyst. CO_2 is not a potential foulant of the catalyst.]

4. The permittee shall install temperature-sensing devices before the oxidation catalyst for units WP1, WP2, and WP3 in order to monitor the inlet temperatures of the catalyst for each engine. Each temperature-sensing device shall be accurate to within 0.75% of span.

5. The engine exhaust temperature for units WP1, WP2, and WP3 at the inlet to the oxidation catalyst, shall be maintained at all times the engines operate at no less than 450°F and no more than 1350°F.

6. If the catalyst inlet temperature on any engine deviates from the acceptable range listed for each engine in section **III.C.5.** above, then the following actions shall be taken:

   (a) Immediately upon determining a deviation of the catalyst inlet temperature, corrective action shall be taken on that engine to assess performance problems and/or tuning issues and the oxidation catalyst shall be inspected for possible damage and problems affecting catalyst effectiveness (including, but not limited to, plugging, fouling, destruction, or poisoning of the catalyst).

   (b) If the problem can be corrected by following the engine and/or the oxidation catalyst manufacturer's recommended procedures, then the permittee shall correct the problem within 24 hours of inspecting the engine and oxidation catalyst.

   (c) If the problem can not be corrected using the manufacturer's recommended procedures, then the affected engine shall cease operating immediately and shall not be returned to routine service until the catalyst inlet temperature is measured and found to be within the acceptable temperature range for that engine. The permittee shall also notify EPA in writing of the problem within 15 working days of observing the problem and include in the notification the cause of the problem and a corrective action plan that outlines the steps and timeframe for bringing the inlet temperature range into compliance. (The corrective action may include removal and cleaning of the oxidation catalyst according to the manufacturer's methods or replacement of the oxidation catalyst.)

7. The permittee shall utilize pressure measuring technology on units WP1, WP2, and WP3 in order to monitor pressure drop across the catalyst.

8. The pressure drop across the catalyst for units WP1, WP2, and WP3 shall not change by more than two (2) inches of water at 100% load plus or minus 10% from the baseline pressure drop across the catalyst measured during the initial performance test. *[Comment: Pressure drop is a good indication of catalyst operation; too low, the catalyst may be blown out; too high, it may be clogged].*

9. If the pressure drop exceeds two (2) inches of water from the baseline pressure drop reading taken during the initial performance test, the cause will be investigated. Investigation may include monitoring CO emissions to ensure the oxidation catalyst is functioning and testing the pressure transducers. If the cause is determined to be the catalyst, then the catalyst shall be inspected and cleaned or replaced, if necessary.

10. The permittee's completion of any or all of the actions prescribed by conditions **III.C.6(a)** through **(c)** and **III.C.9.** of this permit shall not constitute, nor qualify as, an exemption from any CO and CH_2O emission limits in this permit.

III.D. Testing Requirements [40 CFR 71.6(a)(3)(i)(A) through (C)]

1. An initial performance test shall be conducted for engine units WP1, WP2, and WP3 for measuring CO and CH_2O emissions from the engines to demonstrate initial compliance with the emission limits in section **III.B.** The initial performance tests shall be conducted within ninety (90) calendar days of startup of WP1, WP2, and WP3.

2. Upon change out of the catalyst for engine units WP1, WP2, and WP3, a performance test shall be conducted for measuring CO and CH_2O emissions from the engines to demonstrate compliance with the emission limits in section **III.B.** and re-establish temperature and pressure correlations. The performance test shall be conducted within ninety (90) calendar days of the catalyst change out.

3. The performance test for CO shall be conducted in accordance with the test methods specified in 40 CFR part 60, appendix A. EPA Reference Method 10 shall be used to measure CO emissions.

4. The performance test for CH_2O shall be conducted in accordance with the test methods specified in 40 CFR part 63, appendix A. EPA Reference Method 320 or 323 shall be used to measure CH_2O emissions.

5. All tests for CO and CH_2O emissions must meet the following requirements:

    (a) All tests shall be performed at a maximum operating rate (90% to 110% of engine capacity).

    (b) During each test run, data shall be collected on all parameters necessary to document how CO and CH_2O emissions in pounds per hour were measured or calculated (such as test run length, minimum sample volume, volumetric flow rate, moisture and oxygen corrections, etc.). The temperature at the inlet to the catalyst and the pressure drop across the catalyst shall also be measured and recorded during each test run for each engine.

    (c) Each source test shall consist of at least three (3) 1-hour or longer valid test runs. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of the emission limits (pounds per hour and grams per horsepower-hour).

    (d) A source test plan for engine units WP1, WP2, and WP3 for CO and CH_2O emissions shall be submitted to EPA for approval at least forty five (45) calendar days prior to the scheduled performance test.

    (e) The source test plan shall include and address the following elements:

        (i) Purpose of the test;
        (ii) Engines and catalysts to be tested;
        (iii) Expected engine operating rate(s) during test;

(d) Records shall be kept that are sufficient to demonstrate, pursuant to condition **III.C.3.** of this permit, that the fuel for the engines is pipeline-quality natural gas in all respects, with the exception of CO_2 concentration in the natural gas.

2. The permittee shall keep records of all required testing (section **III.D.**) and monitoring (section **III.E.**) in this permit. The records shall include the following:

(a) The date, place, and time of sampling or measurements;

(b) The date(s) analyses were performed;

(c) The company or entity that performed the analyses;

(d) The analytical techniques or methods used;

(e) The results of such analyses or measurements; and

(f) The operating conditions as existing at the time of sampling or measurement.

3. Records shall be kept of off-permit changes, as required by condition **V.Q.** of this permit.

4. The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. These records shall be made available upon request by EPA. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

III.G. Reporting Requirements [40 CFR 71.6(a)(3)(iii)]

1. The permittee shall submit to EPA a written report of the results of the performance tests required in condition **III.D.** of this permit. This report shall be submitted within sixty (60) calendar days of the date of testing completion.

2. The permittee shall submit to EPA, as part of the semi-annual monitoring reports required by condition **IV.B.** of this permit, a report of any instances where the temperature at the inlet to the catalyst is outside the limits established in condition **III.C.**, where the pressure drop across the catalyst is outside the limits established in the initial performance testing, or where an excursion of the CO or CH_2O emission limits has occurred, as well as a description of any corrective actions taken. If no such instances have been detected, then a statement shall be provided to say so.

IV. Facility-Wide Requirements

Conditions in this section of the permit apply to all emissions units located at the facility, including any units not specifically listed in **Tables 2** through **6** of section **I.B.**

[40 CFR 71.6(a)(1)]

IV.A. General Recordkeeping Requirements [40 CFR 71.6(a)(3)(ii)]

The permittee shall comply with the following generally applicable recordkeeping requirements:

1. If a permittee determines that his or her stationary source that emits (or has the potential to emit, without considering controls) one or more hazardous air pollutants is not subject to a relevant standard or other requirement established under 40 CFR part 63, the permittee shall keep a record of the applicability determination at the Operations Center for a period of 5 years after the determination, or until the source changes its operations to become an affected source, whichever comes first. The record of the applicability determination shall include an analysis (or other information) that demonstrates why the owner or operator believes the source is unaffected (e.g., because the source is an area source). The analysis (or other information) shall be sufficiently detailed to allow the Administrator to make a finding about the source's applicability status with regard to the relevant standard or other requirement. If relevant, the analysis shall be performed in accordance with requirements established in subparts of 40 CFR part 63 for this purpose for particular categories of stationary sources. If relevant, the analysis should be performed in accordance with EPA guidance materials published to assist sources in making applicability determinations under section 112, if any.

   [40 CFR 63.10(b)(3)]

2. The permittee is an owner or operator of a glycol dehydration unit that is exempt from the control requirements under §63.764(e)(1). The permittee shall retain the GRI-GLYCalc determination used to demonstrate that actual average benzene emissions are below 1 tpy.

   [40 CFR 63.774(d)(1)]

3. Records shall be kept of off-permit changes, as required by condition **V.Q.** of this permit.

IV.B. General Reporting Requirements [40 CFR 71.6(a)(3)(iii)]

1. The permittee shall submit to EPA reports of any monitoring and recordkeeping required under this permit semi-annually by April 1st and October 1st of each year. The report due on April 1st shall cover the prior six-month period from July 1st through December 31st. The report due on October 1st shall cover the prior six-month period from January 1st through June 30th. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with section **V.E.** of this permit.

2. The permittee shall promptly report to the EPA Regional Office deviations from permit requirements, including those attributable to upset conditions as defined in this permit, the

probable cause of such deviations and any corrective actions or preventive measures taken. "Prompt" is defined as follows:

(a) Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit;

(b) Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence.

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continues for more than two hours in excess of permit requirements, the report must be made within 48 hours.

(iii) For all other deviations from permit requirements, the report shall be submitted with the semi-annual monitoring report.

3. If any of the conditions in **IV.B.2.(b)(i)** or **(ii)**, are met, the source must notify EPA by telephone (1-800-227-8917) or facsimile (303-312-6064) based on the timetables listed above. *[Notification by telephone or fax must specify that this notification is a deviation report for a part 71 permit].* A written notice, certified consistent with section **V.E** of this permit must be submitted within 10 working days of the occurrence. All deviations reported under this section must also be identified in the 6-month report required under permit condition **IV.B.1**.

[Explanatory note: To help part 71 permittees meet reporting responsibilities, EPA has developed a form "PDR" for prompt deviation reporting. The form may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

4. "Deviation" means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or recordkeeping established in accordance with §71.6(a)(3)(i) and (a)(3)(ii). For a situation lasting more than 24 hours which constitutes a deviation, each 24 hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

(a) A situation where emissions exceed an emission limitation or standard;

(b) A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met;

(c) *A situation in which observations or data collected demonstrate noncompliance with an* emission limitation or standard or any work practice or operating condition required by the permit; or

(d) A situation in which an exceedance or an excursion, as defined in 40 CFR part 64 occurs.

IV.C. Permit Shield [40 CFR 71.6(f)(3)]

1. Nothing in this permit shall alter or affect the following:

   (a) The liability of a permittee for any violation of applicable requirements prior to or at the time of permit issuance;

   (b) The ability of the EPA to obtain information under section 114 of the Clean Air Act or;

   (c) The provisions of section 303 of the Clean Air Act (emergency orders), including the authority of the Administrator under that section.

IV.D. Alternative Operating Scenarios [40 CFR 71.6(a)(9) and 40 CFR 71.6(a)(3)(ii)]

Engine Replacement/Overhaul

1. Replacement of an existing permitted compressor engine with a new or overhauled engine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine being replaced, and which satisfies all of the provisions for Off Permit Changes, including the provisions specific to engine replacement, shall be considered an allowed alternative operating scenario under this permit.

2. Any emission limits, requirements, control technologies, testing, or provisions that apply to engines that are replaced under this Alternative Operating Scenarios section (includes, but is not limited to the specific Alternative Operating Scenarios described in Section **I.A.** of this permit) shall also apply to the replacement engines.

3. A replacement engine for units WP1, WP2, or WP3 shall be considered a new unit and thus subject to the initial compliance test required by conditions **II.D., III.D.**, and all other conditions applicable to units WP1, WP2, and WP3 in this permit.

4. Replacement of a permitted compressor engine with an engine subject to 40 CFR part 60, subpart JJJJ is not allowed under this alternative operating scenario.

5. Replacement of a permitted compressor engine with an engine subject to 40 CFR part 63, subpart ZZZZ is not allowed under this alternative operating scenario.

[Explanatory note: This section was included to allow for Off-Permit replacement of engines that may have existing federally enforceable limits. As mentioned in permit condition I.C., for replacement engines which trigger new applicable requirements (i.e., NSPS, NESHAP, etc.), the minor permit modification process (condition V.I. of this permit) shall be utilized to maintain the permitted emission limits of the replaced engine and incorporate the new applicable requirements.]

V. Part 71 Administrative Requirements

V.A. Annual Fee Payment [40 CFR 71.6(a)(7) and 40 CFR 71.9]

1. The permittee shall pay an annual permit fee in accordance with the procedures outlined below.

[40 CFR 71.9(a)]

2. The permittee shall pay the annual permit fee each year no later than April 1st. The fee shall cover the previous calendar year.

[40 CFR 71.9(h)]

3. The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the U.S. Environmental Protection Agency.

[40 CFR 71.9(k)(1)]

4. The permittee shall send fee payment and a completed fee filing form to:

For regular U.S. Postal Service mail

U.S. Environmental Protection Agency
FOIA and Miscellaneous Payments
Cincinnati Finance Center
P.O. Box 979078
St. Louis, MO 63197-9000

For non-U.S. Postal Service Express mail
(FedEx, Airborne, DHL, and UPS)

U.S. Bank
Government Lockbox 979078
U.S. EPA FOIA & Misc. Payments
1005 Convention Plaza
SL-MO-C2-GL
St. Louis, MO 63101

[40 CFR 71.9(k)(2)]

5. The permittee shall send an updated fee calculation worksheet form and a photocopy of each fee payment check (or other confirmation of actual fee paid) submitted annually by the same deadline as required for fee payment to the address listed in section **V.E.** of this permit.

[40 CFR 71.9(h)(1)]

[Explanatory note: The fee filing form "FF" and the fee calculation worksheet form "FEE" may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

6. Basis for calculating annual fee:

   (a) The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of all "regulated pollutants (for fee calculation)" emitted from the source by the presumptive emissions fee (in dollars/ton) in effect at the time of calculation.

[40 CFR 71.9(c)(1)]

(i) "Actual emissions" means the actual rate of emissions in tpy of any regulated pollutant (for fee calculation) emitted from a part 71 source over the preceding calendar year. Actual emissions shall be calculated using each emissions unit's actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year.

[40 CFR 71.9(c)(6)]

(ii) Actual emissions shall be computed using methods required by the permit for determining compliance, such as monitoring or source testing data.

[40 CFR 71.9(h)(3)]

(iii) If actual emissions cannot be determined using the compliance methods in the permit, the permittee shall use other federally recognized procedures.

[40 CFR 71.9(e)(2)]

[Explanatory note: The presumptive fee amount is revised each calendar year to account for inflation, and it is available from EPA prior to the start of each calendar year.]

(b) The permittee shall exclude the following emissions from the calculation of fees:

(i) The amount of actual emissions of each regulated pollutant (for fee calculation) that the source emits in excess of 4,000 tons per year.

[40 CFR 71.9(c)(5)(i)]

(ii) Actual emissions of any regulated pollutant (for fee calculation) already included in the fee calculation.

[40 CFR 71.9(c)(5)(ii)]

(iii) The quantity of actual emissions (for fee calculation) of insignificant activities [defined in §71.5(c)(11)(i)] or of insignificant emissions levels from emissions units identified in the permittee's application pursuant to §71.5(c)(11)(ii).

[40 CFR 71.9(c)(5)(iii)]

7. Fee calculation worksheets shall be certified as to truth, accuracy, and completeness by a responsible official.

[40 CFR 71.9(h)(2)]

[Explanatory note: The fee calculation worksheet form already incorporates a section to help you meet this responsibility.]

8. The permittee shall retain fee calculation worksheets and other emissions-related data used to determine fee payment for 5 years following submittal of fee payment. [Emission-related data include, for example, emissions-related forms provided by EPA and used by the permittee for fee calculation purposes, emissions-related spreadsheets, and emissions-related data, such as records of emissions monitoring data and related support information required to be kept in accordance with §71.6(a)(3)(ii).]

[40 CFR 71.9(i)]

9. Failure of the permittee to pay fees in a timely manner shall subject the permittee to assessment of penalties and interest in accordance with §71.9(l).

[40 CFR 71.9(l)]

10. When notified by EPA of underpayment of fees, the permittee shall remit full payment within 30 days of receipt of notification.

[40 CFR 71.9(j)(2)]

11. A permittee who thinks an EPA assessed fee is in error and who wishes to challenge such fee, shall provide a written explanation of the alleged error to EPA along with full payment of the EPA assessed fee.

[40 CFR 71.9(j)(3)]

V.B. Annual Emissions Inventory [40 CFR 71.9(h)(1)and (2)]

The permittee shall submit an annual emissions report of its actual emissions for both criteria pollutants and regulated HAPS for this facility for the preceding calendar year for fee assessment purposes. The annual emissions report shall be certified by a responsible official and shall be submitted each year to EPA on April 1st.

The annual emissions report shall be submitted to EPA at the address listed in section **V.E.** of this permit.

[Explanatory note: An annual emissions report, required at the same time as the fee calculation worksheet by §71.9(h), has been incorporated into the fee calculation worksheet form as a convenience.]

V.C. Compliance Requirements

1. Compliance with the Permit

(a) The permittee must comply with all conditions of this part 71 permit. Any permit noncompliance constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

[40 CFR 71.6(a)(6)(i)]

(b) It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

[40 CFR 71.6(a)(6)(ii)]

(c) For the purpose of submitting compliance certifications in accordance with section **V.C.2** of this permit, or establishing whether or not a person has violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[Section 113(a) and 113(e)(1) of the Act, 40 CFR 51.212, 52.12, 52.33, 60.11(g), and 61.12.]

2. Compliance Certifications

The permittee shall submit to EPA a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices annually by April 1st, and shall cover the preceding calendar year.

[Explanatory note: To help part 71 permittees meet reporting responsibilities, EPA has developed a reporting form for annual compliance certifications. The form may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

The compliance certification shall be certified as to truth, accuracy, and completeness by a responsible official consistent with §71.5(d).

[40 CFR 71.6(c)(5)]

(a) The certification shall include the following:

(i) Identification of each permit term or condition that is the basis of the certification.

(ii) The identification of the method(s) or other means used for determining the compliance status of each term and condition during the certification period, and whether such methods or other means provide continuous or intermittent data. Such methods and other means shall include, at a minimum, the methods and means required in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information.

(iii) The status of compliance with each term and condition of the permit for the period covered by the certification based on the method or means designated in **(ii)** above. The certification shall identify each deviation and take it into account in the compliance certification.

(iv) Such other facts as the EPA may require to determine the compliance status of the source.

(v) Whether compliance with each permit term was continuous or intermittent.

[40 CFR 71.6(c)(5)(iii)]

2. Compliance Schedule

3. For applicable requirements with which the source is in compliance, the source will continue to comply with such requirements.

[40 CFR 71.5(c)(8)(iii)(A)]

4. For applicable requirements that will become effective during the permit term, the source shall meet such requirements on a timely basis.

[40 CFR 71.5(c)(8)(iii)(B)]

V.D. Duty to Provide and Supplement Information
[40 CFR 71.6(a)(6)(v), 71.5(a)(3), and 71.5(b)]

1. The permittee shall furnish to EPA, within a reasonable time, any information that EPA may request in writing to determine whether cause exists for modifying, revoking, and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to the EPA copies of records that are required to be kept pursuant to the terms of the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of 40 CFR part 2, subpart B.

[40 CFR 71.6(a)(6)(v) and 71.5(a)(3)]

2. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. In addition, a permittee shall provide additional information as necessary to address any requirements that become applicable after the date a complete application is filed, but prior to release of a draft permit.

[40 CFR 71.5(b)]

V.E. Submissions [40 CFR 71.5(d), 71.6(c)(1) and 71.9(h)(2)]

1. Any document (application form, report, compliance certification, etc.) required to be submitted under this permit shall be certified by a responsible official as to truth, accuracy, and completeness. Such certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

[Explanatory note: EPA has developed a reporting form "CTAC" for certifying truth, accuracy and completeness of part 71 submissions. The form may be found on EPA website at: http://www.epa.gov/air/oaqps/permits/p71forms.html]

5. Any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted to:

   Part 71 Permit Contact
   Air Program, 8P-AR
   U.S. Environmental Protection Agency,
   1595 Wynkoop Street
   Denver, Colorado 80202-1129

V.F. Severability Clause [40 CFR 71.6(a)(5)]

The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force.

V.G. Permit Actions [40 CFR 71.6(a)(6)(iii)]

This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

V.H. Administrative Permit Amendments [40 CFR 71.7(d)]

1. The permittee may request the use of administrative permit amendment procedures for a permit revision that:

   (a) Corrects typographical errors;

   (b) Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;

   (c) Requires more frequent monitoring or reporting by the permittee;

   (d) Allows for a change in ownership or operational control of a source where the EPA determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the EPA;

   (e) Incorporates into the part 71 permit the requirements from preconstruction review permits authorized under an EPA-approved program, provided that such a program meets procedural requirements substantially equivalent to the requirements of §§71.7 and 71.8 that would be applicable to the change if it were subject to review as a permit modification, and compliance requirements substantially equivalent to those contained in §71.6; or

(f) Incorporates any other type of change which EPA has determined to be similar to those listed above in subparagraphs **(a)** through **(e)** above. *[Note to permittee: If subparagraphs (a) through (e) above do not apply, please contact EPA for a determination of similarity prior to submitting your request for an administrative permit amendment under this provision.]*

V.I. Minor Permit Modifications [40 CFR 71.7(e)(1)]

1. The permittee may request the use of minor permit modification procedures only for those modifications that:

   (a) Do not violate any applicable requirement;

   (b) Do not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in the permit;

   (c) Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

   (d) Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

      (i) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of title I; and

      (ii) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Clean Air Act;

   (e) Are not modifications under any provision of title I of the Clean Air Act; and

   (f) Are not required to be processed as a significant modification.

[40 CFR 71.7(e)(1)(i)(A)]

2. Notwithstanding the list of changes ineligible for minor permit modification procedures in paragraph **1** above, minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in an applicable implementation plan or in applicable requirements promulgated by EPA.

[40 CFR 71.7(e)(1)(i)(B)]

3. An application requesting the use of minor permit modification procedures shall meet the requirements of §71.5(c) and shall include the following:

   (a) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

   (b) The source's suggested draft permit;

   (c) Certification by a responsible official, consistent with §71.5(d), that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

   (d) Completed forms for the permitting authority to use to notify affected States as required under §71.8.

[40 CFR 71.7(e)(1)(ii)]

4. The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by §71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR 71.7(e)(1)(v)]

5. The permit shield under §71.6(f) may not extend to minor permit modifications.

[40 CFR 71.7(e)(1)(vi)]

V.J. Group Processing of Minor Permit Modifications. [40 CFR 71.7(e)(2)]

1. Group processing of modifications by EPA may be used only for those permit modifications:

   (a) That meet the criteria for minor permit modification procedures under section **V.I.** of this permit; and

   (b) That collectively are below the threshold level of 10 percent of the emissions allowed by the permit for the emissions unit for which the change is requested, 20 percent of the applicable definition of major source in §71.2, or 5 tons per year, whichever is least.

[40 CFR 71.7(e)(2)(i)]

2. An application requesting the use of group processing procedures shall be submitted to EPA, shall meet the requirements of §71.5(c), and shall include the following:

(a) A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

(b) The source's suggested draft permit;

(c) Certification by a responsible official, consistent with §71.5(d), that the proposed modification meets the criteria for use of group processing procedures and a request that such procedures be used;

(d) A list of the source's other pending applications awaiting group processing, and a determination of whether the requested modification, aggregated with these other applications, equals or exceeds the threshold set under subparagraph **(1)(b)** above; and

(e) Completed forms for the permitting authority to use to notify affected States as required under §71.8.

[40 CFR 71.7(e)(2)(ii)]

3. The source may make the change proposed in its minor permit modification application immediately after it files such application. After the source makes the change allowed by the preceding sentence, and until the permitting authority takes any of the actions authorized by §71.7(e)(1)(iv)(A) through (C), the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time period, the source need not comply with the existing permit terms and conditions it seeks to modify. However, if the source fails to comply with its proposed permit terms and conditions during this time period, the existing permit terms and conditions it seeks to modify may be enforced against it.

[40 CFR 71.7(e)(2)(v)]

4. The permit shield under §71.6(f) does not extend to group processing of minor permit modifications.

[40 CFR 71.7(e)(1)(vi)]

V.K. Significant Permit Modifications [40 CFR 71.7(e)(3)]

1. The permittee must request the use of significant permit modification procedures for those modifications that:

(a) Do not qualify as minor permit modifications or as administrative amendments;

(b) Are significant changes in existing monitoring permit terms or conditions; or

(c) Are relaxations of reporting or recordkeeping permit terms or conditions.

[40 CFR 71.7(e)(3)(i)]

2. Nothing herein shall be construed to preclude the permittee from making changes consistent with part 71 that would render existing permit compliance terms and conditions irrelevant.

[40 CFR 71.7(e)(3)(i)]

3. Permittees must meet all requirements of part 71 for applications, public participation, and review by affected states and tribes for significant permit modifications. For the application to be determined complete, the permittee must supply all information that is required by §71.5(c) for permit issuance and renewal, but only that information that is related to the proposed change.

[40 CFR 71.7(e)(3)(ii), 71.8(d), and 71.5(a)(2)]

V.L. Reopening for Cause [40 CFR 71.7(f)]

The permit may be reopened and revised prior to expiration under any of the following circumstances:

1. Additional applicable requirements under the Act become applicable to a major part 71 source with a remaining permit term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended pursuant to §71.7 (c)(3);

2. Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

3. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or

4. EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

V.M. Property Rights [40 CFR 71.6(a)(6)(iv)]

This permit does not convey any property rights of any sort, or any exclusive privilege.

V.N. Inspection and Entry [40 CFR 71.6(c)(2)]

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow EPA or an authorized representative to perform the following:

1. Enter upon the permittee's premises where a part 71 source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

4. As authorized by the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

V.O. Emergency Provisions [40 CFR 71.6(g)]

1. In addition to any emergency or upset provision contained in any applicable requirement, the permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

   (a) An emergency occurred and that the permittee can identify the cause(s) of the emergency;

   (b) The permitted facility was at the time being properly operated;

   (c) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

   (d) The permittee submitted notice of the emergency to EPA within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirements for prompt notification of deviations.

2. In any enforcement proceeding the permittee attempting to establish the occurrence of an emergency has the burden of proof.

3. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

V.P. Transfer of Ownership or Operation [40 CFR 71.7(d)(1)(iv)]

A change in ownership or operational control of this facility may be treated as an administrative permit amendment if the EPA determines no other change in this permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to EPA.

V.Q. Off Permit Changes [40 CFR 71.6(a)(12) and 40 CFR 71.6(a)(3)(ii)]

The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met, and that all records required by this section are kept at the Operations Center for a period of five years:

1. Each change is not addressed or prohibited by this permit;

2. Each change shall meet with all applicable requirements and shall not violate any existing permit term or condition;

3. Changes under this provision may not include changes subject to any requirement of 40 CFR parts 72 through 78 or modifications under any provision of title I of the Clean Air Act;

4. The permittee must provide contemporaneous written notice to EPA of each change, except for changes that qualify as insignificant activities under §71.5(c)(11). The written notice must describe each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change;

5. The permit shield does not apply to changes made under this provision;

6. The permittee must keep a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes;

7. For replacement of an existing permitted compressor engine with a new or overhauled engine of the same make, model, horsepower rating, and configured to operate in the same manner as the engine being replaced, in addition to satisfying all other provisions for off permit changes, the permittee satisfies the following provisions:

    (a) The replacement engine employs air emissions control devices, monitoring, record keeping and reporting that are equivalent to those employed by the engine being replaced;

    (b) The replacement of the existing engine does not constitute a major modification or major new source as defined in Federal PSD regulations (40 CFR 52.21);

    (c) No new applicable requirements, as defined in 40 CFR 71.2, are triggered by the replacement; and

    (d) The following information is provided in a written notice to EPA, prior to installation of the replacement engine, in addition to the standard information listed above for contemporaneous written notices for off permit changes:

        (i) Make, model number, serial number, horsepower rating and configuration of the existing engine and the replacement engine;

(ii) Manufacture date, commence construction date (per the definitions in 40 CFR 60.4230(a) and 63.2), and installation date of the replacement engine at the facility;

(iii) If applicable, documentation of the cost to rebuild a replacement engine versus the cost to purchase a new engine in order to support claims that an engine is not "reconstructed", as defined in 40 CFR 60.15 and 40 CFR 63.2.

(iv) 40 CFR part 60, subpart IIII (CI Engine NSPS) non-applicability documentation as appropriate;

(v) 40 CFR part 60, subpart JJJJ (SI Engine NSPS) non-applicability documentation as appropriate;

(vi) 40 CFR part 63, subpart ZZZZ (RICE MACT) non-applicability documentation for major sources, as appropriate;

(vii) 40 CFR part 63, subpart ZZZZ (RICE MACT) non-applicability documentation for area sources, as appropriate;

(viii) Documentation to demonstrate that the replacement does not constitute a major new source or major modification, as defined in Federal PSD rules (40 CFR 52.21), as follows:

(A) If the replacement will not constitute a "physical change or change in the method of operation" as described in §52.21(b)(2)(i), an explanation of how that conclusion was reached shall be provided.

(B) If the replacement will constitute a "physical change or change in the method of operation" as described §52.21(b)(2)(i), the following information shall be provided:

(1) If the existing source is a "major stationary source" as defined in §52.21(b)(1): For each "regulated NSR pollutant" as defined in §52.21(b)(50), a demonstration (including all calculations) that the replacement will not be a "major modification" as defined in §52.21(b)(2). A modification is major only if it causes a "significant emissions increase" as defined in §52.21(b)(40), and also causes a "significant net emissions increase" as defined in §§52.21(b)(3) and (b)(23).

The procedures of §52.21(a)(2)(iv) shall be used to calculate whether or not there will be a significant emissions increase. If there will be a significant emissions increase, then calculations shall be provided to demonstrate there will not be a significant net emissions increase. These latter calculations shall include all sourcewide contemporaneous and creditable emission increases and decreases, as defined in §52.21(b)(3), summed with the PTE of the replacement unit(s).

If netting is used to demonstrate that the replacement will not constitute a "major modification," verification shall be provided that the replacement engine(s) or turbine(s) employ emission controls at least equivalent in control effectiveness to those employed by the engine(s) or turbine(s) being replaced.

PTE of replacement unit(s) shall be determined based on the definition of PTE in §52.21(b)(4). For each "regulated NSR pollutant" for which the PTE is not "significant," calculations used to reach that conclusion shall be provided.

(2) If the existing source is not a "major stationary source" as defined in §52.21(b)(1): For each "regulated NSR pollutant," a demonstration (including all calculations) that the replacement engine(s) or turbine(s), by itself, will not constitute a "major stationary source" as defined in §52.21(b)(1)(i).

8. The notice shall be kept at the Operations Center and made available to EPA on request, in accordance with the general recordkeeping provision of this permit; and

9. Submittal of the written notice required above shall not constitute a waiver, exemption, or shield from applicability of any applicable standard or PSD permitting requirements under 40 CFR 52.21 that would be triggered by the replacement of any one engine, or by replacement of multiple engines.

V.R. Permit Expiration and Renewal [40 CFR 71.5(a)(1)(iii), 71.5(a)(2), 71.5(c)(5), 71.6(a)(11), 71.7(b), 71.7(c)(1) and 71.7(c)(3)]

1. This permit shall expire upon the earlier occurrence of the following events:

   (a) Five (5) years elapses from the date of issuance; or

   (b) The source is issued a part 70 or part 71 permit under an EPA approved or delegated permit program.

[40 CFR 71.6(a)(11)]

2. Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least 6 months but not more than 18 months prior to the date of expiration of this permit.

[40 CFR 71.5(a)(1)(iii)]

3. If the permittee submits a timely and complete permit application for renewal, consistent with §71.5(a)(2), but EPA has failed to issue or deny the renewal permit, then all the

terms and conditions of the permit, including any permit shield granted pursuant to §71.6(f) shall remain in effect until the renewal permit has been issued or denied.

[40 CFR 71.7(c)(3)]

4. The permittee's failure to have a part 71 permit is not a violation of this part until EPA takes final action on the permit renewal application. This protection shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit any additional information identified as being needed to process the application by the deadline specified in writing by EPA.

[40 CFR 71.7(b)]

5. Renewal of this permit is subject to the same procedural requirements that apply to initial permit issuance, including those for public participation, affected State, and tribal review.

[40 CFR 71.7(c)(1)]

6. The application for renewal shall include the current permit number, description of permit revisions and off-permit changes that occurred during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form.

[40 CFR 71.5(a)(2) and 71.5(c)(5)]

VI. Appendix

VI.A. Inspection Information

1. Driving Directions to Plant From Aztec, New Mexico:

    (a) Go north on Highway 550 to County Road 318 and take a right turn (approximately 17.4 miles)
    (b) Go 5.6 miles and turn left onto County road 310
    (c) Go 1.9 miles and turn left onto private gravel road.
    (d) Go 0.9 miles and take a right at the Y.
    (e) Continue on the gravel road 0.8 miles to the site.

2. Latitude and Longitude coordinates:

    Lat. 37.10743378, Long -107.8353513

3. Safety Considerations:

All visitors to the Wolf Point Compressor Station are required to wear a hard hat, safety glasses, safety toe footwear, hearing protection, and fire resistant clothing (FRC).

EXHIBIT 7

Draft Statement of Basis for Permit No. V-SU-0034-07.00

Air Pollution Control
Title V Permit to Operate
Draft Statement of Basis for Permit No. V-SU-0034-07.00
First Permit Renewal

BP America Production Company
Wolf Point Compressor Station
Southern Ute Reservation
La Plata County, Colorado

1. Facility Information

a. Location

BP America Production Company's Wolf Point Compressor Station is located within the exterior boundaries of the Southern Ute Indian Reservation in the southwestern part of the State of Colorado. The exact location is NW ¼ Section 16, T33N, R9W, in La Plata County, Colorado. The mailing address is:

BP America Production Company
380 Airport Road
Durango, CO 81303

b. Contacts

The Facility Contact:
Julie A. Best
Environmental Coordinator
380 Airport Road
Durango, CO 81303
970-375-7540

The Responsible Official:
Kourtney K. Hadrick
Florida Operations Manager
2906 County Road 307
Durango, CO 81303
970-247-6901

The Parent Company Contact:
Rebecca Tanory
Environmental Specialist
501 Westlake Park Boulevard
Houston, TX 77079
281-366-3946

The Alternate Responsible Official:
David P. McKenna
Operations Center Manager
380 Airport Road
Durango, CO 81303
970-247-6810

The Tribal Contact:
Christopher Lee
Air Program Manager - Southern Ute Indian Tribe
(970)-563-4705

c. Description of operations

BP America Production Company (BP) owns and operates the Wolf Point Compressor Facility. Fruitland coal bed methane wells feed into a gathering pipeline system leading to the inlet of this facility. The natural gas produced from these wells contains approximately 93% methane and 7% carbon dioxide and is water vapor saturated. The wells do not produce any condensate or natural gas liquids.

Upon entering the compressor station, the gas first passes through an inlet separator vessel to remove any free liquids in the gas stream by gravity. The gas then passes to a filter vessel, which serves to filter out any solids such as coal dust in the gas. The gas is then compressed and finally passes through an outlet coalescer vessel which removes any entrained droplets of lubricating oil before being metered and sent to the BP Florida River Compressor Facility for further processing. In addition, there are no pigging facilities or operations associated with this station.

d. Permitting and/or construction history

The Wolf Point Compressor Station was constructed in 2001 to provide field compression for natural gas wells in the area. The first two Waukesha L7042GL reciprocating engines, fueled by natural gas, became operational on May 1, 2001. The third Waukesha L7042GL reciprocating engine became operational on May 15, 2001. The fourth Waukesha L7042GL reciprocating engine became operational in October 2005. EPA has never issued a pre-construction permit for the Wolf Point Compressor Station. On February 27, 2003, EPA issued an initial title V (part 71) Permit to Operate the Wolf Point Compressor Station. On September 19, 2005, EPA issued an administrative amendment to the part 71 permit (V-SU-0034-02.01), which corrected the facility location, added the latitude and longitude coordinates, and added an Alternate Responsible Official. On February 7, 2006, EPA issued a minor modification to the part 71 permit (V-SU-0034-02.02), which updated the Tribal Contact name, added an engine, and updated emission factors.

On March 27, 2006, EPA received a request to significantly modify the part 71 permit. In this modification request, BP proposed removing the four existing Waukesha L7042GL reciprocating engines and installing three new Caterpillar G3606 engines with catalytic controls for carbon monoxide (CO) and formaldehyde (CH_2O) emissions so that the facility total emissions remained below the applicability thresholds for the Reciprocating Internal Combustion Engine Maximum Achievable Control Technology Requirements (RICE MACT, 40 CFR Part 63, Subpart ZZZZ). BP requested that the part 71 permit be modified to include enforceable conditions to assure minor source status for hazardous air pollutants (HAP) with regard to applicability to the MACT regulations. On July 21, 2006, EPA issued the significant modification to the part 71 permit (V-SU-0034-02.03). The proposed modifications were never made at the facility.

On September 28, 2007, EPA issued an administrative amendment to the part 71 permit (V-SU-0034-02.04), which changed the plant mailing address, updated the names and contact information for the Alternate Responsible Official and Facility Contact, and revised the text for Alternative Operating Scenarios and Off Permit Changes to clarify the requirements.

e. Description of Draft First Permit Renewal

On September 10, 2007, EPA received an application for renewal of the part 71 permit. EPA determined the application complete on September 10, 2007. The three Caterpillar G3606 compressor engines authorized in the current permit with federally enforceable emission limits have not yet been installed, because of a change in the intended replacement schedule; therefore, the permit does not reflect the actual equipment operating at the facility, or the current major HAP emission status. In the permit renewal application, BP requested that the existing engines be added back into the permit, the specific emission-limiting conditions for the replacement engines be removed from the permit, and an alternative operating scenario be added, under which the new engines may be installed at a later date. At the time EPA received the application for renewal, this replacement project was anticipated to begin in 2008, with operation in later 2008 or early 2009. Concurrent with installation of the new engines, the existing engines will be removed from service.

BP proposed to conduct the engine replacement project in phases to avoid major HAP source status and subsequently triggrting applicability to the requirements of the RICE MACT. In order to maintain the facility's permitted minor HAP status, BP proposed two potential alternative operating scenarios for phase I of the project under which three of the existing four Waukesha L7042GL engines (exact units not specified) would be removed from service, followed by installation of two of three Caterpillar G3606 engines. For the second phase of the engine replacement project (another alternative operating scenario), the fourth Waukesha L7042GL engine would be removed, followed by installation of a third Caterpillar G3606 engine. This phased process will keep the maximum potential to emit formaldehyde below the HAP major source trigger of ten tons per year (tpy) throughout the replacement project. BP also stated in the application that additional insignificant equipment may be added as part of the engine replacement project and proposed to submit an application for a minor modification of the permit upon completion of the engine replacement project.

Based on discussions between EPA and BP after submittal of the renewal application, BP expressed a desire to keep the specific emission limiting conditions for the replacement engines in the permit in order to maintain establishment of the synthetic minor limits. Because the effective permit does not reflect actual current operations and emission status, and because BP did not specify which particular emission units would be removed and installed during each phase of the proposed engine replacement project, for clarification purposes, EPA separately identified specific operating scenarios in the draft permit, as shown in the table below, and wrote specific requirements into the draft permit that are dependent on the scenario under which the facility is operating at any given time. It is important to note that establishment of the enforceable synthetic minor limits for the alternative operating scenarios is only designed to protect the source from major HAP status and subsequent applicability to MACT standards for major sources. As discussed in the remainder of this Statement of Basis, the established enforceable limits will not protect the source from potential applicability to any recently promulgated MACT standards for area sources, or separately enforceable New Source Performance Standards (NSPS).

Table 1 – Potential Facility Operating Scenarios
BP Wolf Point Compressor Station

Operating Scenario	Emission Units Operating
Current* Operating Scenario	C1, C2 , C3, C4, G1
Alternative Operating Scenarios #1a - #1c	C1 (#1a) or C2(#1b) or C3 (#1c), G1, WP1, WP2
Alternative Operating Scenario #2	C4, G1, WP1, WP2
Alternative Operating Scenario #3	G1, WP1, WP2, WP3

* The most recent Part 71 permit (V-SU-0034-02.04) authorized emission units G1 and three Caterpillar G3606 natural gas compression engines (WP1, WP2, and WP3); however, due to changes in the installation schedule, the Caterpillar engines have not yet been installed and four previously permitted (V-SU-0034-02.02) Waukesha L7042GL engines are currently operating at the facility.

In addition to the changes described above for renewal of the part 71 permit, the following changes have also been made as part of the draft renewal permit. On October 22, 2007, EPA received a letter from BP, dated September 10, 2007, with notification of an off permit replacement of emission unit C4 with an existing leased engine of identical make, model, horsepower, and emission control equipment (not federally enforceable). The change will not result in any change in emissions and the engine will operate in the same configuration and service as the existing engine. The only change made to the draft renewal permit was to replace the serial number of the existing engine with that of the replacement engine. On November 5, 2007, EPA received a request for an administrative amendment to change the responsible official for the facility from Dennis E. Scott to Kourtney K. Hadrick. On November 8, 2007, EPA sent a letter to inform BP of a new mailing address, effective December 17, 2007, for the submittal of the annual fee payments required pursuant to 40 CFR part 71 and the title V Permits issued by EPA's Office of Air and Radiation. The fee payment bank name and address has been corrected in the Annual Fee Payment section of the draft renewal permit (section V.A.).

Additionally, in an effort to streamline the title V permits and reduce the number of administrative permit amendments requested, EPA is modifying the structure of the permit, including removing specific non-enforceable facility information, such as the names and phone numbers of the Responsible Official, Facility Contact, and Tribal Contact, as well as the plant mailing address. Part 71 does not require this information to be in the permit and changes to such information are the most often requested administrative permit amendments. This information will be maintained in the Statements of Basis for each permit action. EPA requests from this point forward that BP continue to send notification in writing of changes to such facility information; however, the changes will no longer require administrative permit amendments. The notifications will be kept on file, similar to Off Permit Change notifications, and the most current information will be updated in the Statement of Basis as part of the next permit modification or renewal. The change in responsible official that BP requested on November 5, 2007 is being represented in this Statement of Basis, because this information has been removed from the draft renewal permit.

f. List of all units and emission-generating activities

BP America Production Company provided in their application the information contained in Tables 2 through 5 for this facility, which list emission units and emission generating activities, including any air pollution control devices. Emission units identified as "insignificant" are listed separately in Table 6.

Table 2 - Emission Units – Current* Operating Scenario
BP Wolf Point Compressor Station

Emission Unit Id. No.	Description	Control Equipment
	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engines	None
C1	Serial No. 316401 Rebuilt**/Installed: 4/15/06 (constructed 12/20/1977)	
C2	Serial No. C61492/1 Rebuilt**/Installed: 5/19/06 (constructed 12/11/1998)	
C3	Serial No. 296963 Installed: 2001	
	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engine	Oxicat controller (not federally enforceable)
C4	Serial No. 351077 Rebuilt**/Installed: 9/11/2007 (constructed 2001 at BP Red Willow)	
	59 hp, lean burn, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	None
G1	Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	

* Most recent Part 71 permit (V-SU-0034-02.04) authorized emission units G1 and three new Caterpillar G3606 natural gas compression engines (WP1, WP2, and WP3); however, due to changes in the installation schedule, these engines have not yet been installed and four previously permitted Waukesha L7042GL engines are currently operating at the facility.

** The term "rebuilt" is not to be confused with the term "reconstruction", as defined in 40 CFR 63.2. According to BP, these engines have previously operated at other facilities and have been modified for a cost less than 50% of the cost to purchase a new engine, and are therefore, not considered "reconstructed" after 12/19/2002 and thus not subject to 40 CFR part 63, subpart ZZZZ.

Table 3 - Emission Units – Alternative Operating Scenarios #1a - #1c
BP Wolf Point Compressor Station

Emission Unit Id. No.	Description	Control Equipment
   C1 (scenario #1a) or C2 (scenario #1b) or C3 (scenario #1c)	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engines Serial No. 316401 Rebuilt*/Installed: 4/15/06 (constructed 12/20/1977) Serial No. C61492/1 Rebuilt*/Installed: 5/19/06 (constructed 12/11/1998) Serial No. 296963 Installed: 2001	None
   WP1 WP2	1895 hp, lean burn, natural gas-fired Caterpillar G3606 Compressor Engines (either 90°F or 129° F Engine Control Modules (ECM)) Serial No. TBD Projected Installation: 2008/2009 Serial No. TBD Projected Installation: 2008/2009	Oxicat controllers
  G1	59 hp, lean burn, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine) Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	None

** The term "rebuilt" is not to be confused with the term "reconstruction", as defined in 40 CFR 63.2. According to BP, these engines have previously operated at other facilities and have been modified for a cost less than 50% of the cost to purchase a new engine, and are therefore not considered "reconstructed" after 12/19/2002 and thus not subject to 40 CFR part 63, subpart ZZZZ.

Table 4 - Emission Units – Alternative Operating Scenario #2
BP Wolf Point Compressor Station

Emission Unit Id. No.	Description	Control Equipment
  C4	1323 hp, lean burn, natural gas-fired Waukesha L7042GL Compressor Engines Serial No. 351077 Rebuilt*/Installed: 9/11/2007 (constructed 2001 at BP Red Willow)	Oxicat controller (not federally enforceable)
   WP1 WP2	1895 hp, lean burn, natural gas-fired Caterpillar G3606 Compressor Engines (either 90°F or 129° F ECM) Serial No. TBD Projected Installation: 2008/2009 Serial No. TBD Projected Installation: 2008/2009	Oxicat controllers
  G1	59 hp, lean burn, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine) Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	None

** The term "rebuilt" is not to be confused with the term "reconstruction" as defined in 40 CFR 63.2. According to BP, this engine has previously operated at another facility and has been modified for a cost less than 50% of the cost to purchase a new engine, and is therefore not considered "reconstructed" after 12/19/2002 and thus not subject to 40 CFR part 63, subpart ZZZZ.

Table 5 - Emission Units – Alternative Operating Scenario #3
BP Wolf Point Compressor Station

Emission Unit Id. No.	Description	Control Equipment
	1895 hp, lean burn, natural gas-fired Caterpillar G3606 Compressor Engines (either 90°F or 129° F ECM)	Oxicat controllers
WP1	Serial No. TBD Projected Installation: 2008/2009	
WP2	Serial No. TBD Projected Installation: 2008/2009	
WP3	Serial No. TBD Projected Installation: 2008/2009	
	59 hp, natural gas-fired Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	None
G1	Serial No. 0685338 (generator) Installed: 2001 5.7L-05349 (engine)	

Part 71 allows sources to separately list in the permit application units or activities that qualify as "insignificant" based on potential emissions below 2 tons/year for all regulated pollutants that are not listed as HAP under section 112(b) and below 1000 lbs/year or the deminimus level established under section 112(g), whichever is lower, for HAPs. However, the application may not omit information needed to determine the applicability of, or to impose, any applicable requirement, or to calculate the fee. Units that qualify as "insignificant" for the purposes of the part 71 application are in no way exempt from applicable requirements or any requirements of the part 71 permit.

Table 6 - Insignificant Emission Units (All Operating Scenarios)
BP Wolf Point Compressor Station

Emission Unit ID	Description
1	Process Fugitive Emissions
2	Compressor Blowdowns, max of 395 MMscf/yr
3	4 - 500 gallon (or one 2,000 gallon) Used Oil Tanks
4	4 - 500 gallon (or one 2,000 gallon) Lube Oil Tanks
5	1 - 300 bbl Produced Water Tank
6	1 - 0.5 MMBtu/hr heater for the produced water tank
7	1 - 300 bbl Produced Water/Oily Water Tank
8	1 - 0.5 MMBtu/hr heater for the produced water/oily water tank
9	2 – 286 bbl Water Tanks
10	2 – 0.5 MMBtu/hr Heater for the water tanks
11	1 – 575 gallon TEG Tank
12	1 – 0.25 MMBtu/hr Dehy Reboiler
13	1 - 2.0 MMscfd Glycol Still Column Vent
14	1 - 750 gallon Ethylene Glycol Tank
15	1 – 21 bbl Lube Oil Drip Tank

*BP may install additional insignificant equipment as part of the engine replacement project, but BP will address the authorization of this equipment at the time of installation, through a minor permit modification after the engine replacement project is completed (Alternative Operating Scenario #3).

g. Potential to emit

PTE means the maximum capacity of the Wolf Point Compressor Station to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of Wolf Point Compressor Station to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, may be treated as part of its design if the limitation is enforceable by EPA (see section 2.0). Potential to emit is meant to be a worse case emissions calculation. Actual emissions may be much lower.

The PTE for the facility as a whole are as follows for the Current Operations:

Current Operations

Nitrogen Oxides (NO_x) – 83.26 tpy
Carbon Monoxide (CO) – 180.14 tpy
Volatile Organic Compounds (VOC) – 54.45 tpy
Small Particulates (PM_{10}) – 1.81 tpy
Sulfur Dioxide (SO_2) - 0.1 tpy
Total Hazardous Air Pollutants (HAPs) – 14.89 tpy
Largest Single HAP (formaldehyde, CH_2O) – 14.89 tpy

The PTE for the Wolf Point Compressor Station, with emission controls taken into consideration (see section 2.0) for Alternative Operating Scenarios #1a-#1c, #2, and #3, are proposed as follows:

Alternative Operating Scenarios #1a - #1c

Nitrogen Oxides (NO_x) – 50.11 tpy
Carbon Monoxide (CO) – 74.32 tpy
Volatile Organic Compounds (VOC) – 52.35 tpy
Small Particulates (PM_{10}) – 1.69 tpy
Sulfur Dioxide (SO_2) - 0.09 tpy
Total Hazardous Air Pollutants (HAPs) – 9.63 tpy
Largest Single HAP (formaldehyde, CH_2O) – 9.63 tpy

Alternative Operating Scenario #2

Nitrogen Oxides (NO_x) – 51.39 tpy
Carbon Monoxide (CO) – 74.32 tpy
Volatile Organic Compounds (VOC) – 52.35 tpy
Small Particulates (PM_{10}) – 1.69 tpy
Sulfur Dioxide (SO_2) - 0.09 tpy
Total Hazardous Air Pollutants (HAPs) – 9.63 tpy
Largest Single HAP (formaldehyde, CH_2O) – 9.63 tpy

Alternative Operating Scenario #3

Nitrogen Oxides (NO_x) – 43.76 tpy
Carbon Monoxide (CO) – 40.57 tpy
Volatile Organic Compounds (VOC) – 57.69 tpy
Small Particulates (PM_{10}) – 1.83 tpy
Sulfur Dioxide (SO_2) - 0.1 tpy
Total Hazardous Air Pollutants (HAPs) – 8.85 tpy
Largest Single HAP (formaldehyde, CH_2O) – 8.85 tpy

Tables 7 through 10 below illustrate the difference in facility-wide emissions that would result from each of the phased Alternative Operating Scenarios proposed in the application when compared to the Current Operating Scenario.

Table 7 - Current Operating Scenario - Summary of Potential Emissions BP Wolf Point Compressor Station

Emission Unit ID	Description	Uncontrolled Emissions (tpy)					
		NOx	CO	PM	SO_2	VOC	CH_2O
C1	1323 hp Waukesha L7042GL (uncontrolled)	19.16	38.33	0.41	0.02	12.78	3.70
C2	1323 hp Waukesha L7042GL (uncontrolled)	19.16	38.33	0.41	0.02	12.78	3.70
C3	1323 hp Waukesha L7042GL (uncontrolled)	19.16	38.33	0.41	0.02	12.78	3.70
C4	1323 hp Waukesha L7042GL with oxidation catalyst (not federally enforceable, calculations are uncontrolled)	20.44	38.33	0.41	0.02	12.78	3.70
G1	59 hp Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	4.10	25.81	0.06	0.00	1.14	0.07
IEUs	Insignificant Emission Units	1.23	1.04	0.09	0.002	2.21	0.0009
Total		**83.26**	**180.14**	**1.81**	**0.10**	**54.45**	**14.89**

- Existing minor source for PSD. Major HAP source.
- Waukesha engines are "existing" and, therefore, not subject to the requirements of 40 CFR 63, subpart ZZZZ.

Table 8 - Alternative Operating Scenarios #1a-1c – Summary of Potential Emissions BP Wolf Point Compressor Station

Emission Unit ID	Description	Controlled Emissions (tpy)						Uncontrolled Emissions (tpy)	
		NOx	CO	PM	SO_2	VOC	CH_2O	CO	CH_2O
C1 or C2 or C3	1323 hp Waukesha L7042GL (uncontrolled)	19.16	38.33	0.41	0.02	12.78	3.70	38.33	3.70
G1	59 hp Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	4.10	25.81	0.06	0.00	1.14	0.07	25.81	0.07
WP1	1895 hp Caterpillar G3606 Compressor Engine w/Oxidation Catalyst	12.81	4.57	0.56	0.03	18.12	2.93	45.75	7.32
WP2	1895 hp Caterpillar G3606 Compressor Engine w/Oxidation Catalyst	12.81	4.57	0.56	0.03	18.12	2.93	45.75	7.32
IEUs	Insignificant Emission Units	1.23	1.04	0.09	0.002	2.21	0.0009	1.04	0.0009
Total		**50.11**	**74.32**	**1.69**	**0.09**	**52.35**	**9.63**	**156.68**	**18.41**

- Remove three existing Waukesha L7042GL compressor engines (C2, C3, C4) and install two Caterpillar G3606 compressor engines.
- Project does not trigger PSD. Minor HAP source with federally enforceable synthetic minor emission limits on Caterpillar engines, therefore replacement Caterpillar engines not subject to 40 CFR 63, subpart ZZZZ, provided they are not "new" engines, as defined in the subpart.

Table 9 - Alternative Operating Scenario #2 – Summary of Potential Emissions BP Wolf Point Compressor Station

Emission Unit ID	Description	Controlled Emissions (tpy)						Uncontrolled Emissions (tpy)	
		NOx	CO	PM	SO_2	VOC	CH_2O	CO	CH_2O
C4	1323 hp Waukesha L7042GL with oxicat (not federally enforceable, calculations are uncontrolled)	20.44	38.33	0.41	0.0244	12.78	3.70	38.33	3.70
G1	59 hp Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	4.10	25.81	0.06	0.0006	1.14	0.07	25.81	0.07
WP1	1895 hp Caterpillar G3606 Compressor Engine w/Oxidation Catalyst	12.81	4.57	0.56	0.0329	18.12	2.93	45.75	7.32
WP2	1895 hp Caterpillar G3606 Compressor Engine w/ Oxidation Catalyst	12.81	4.57	0.56	0.0329	18.12	2.93	45.75	7.32
IEUs	Insignificant Emission Units	1.23	1.04	0.09	0.002	2.21	0.0009	1.04	0.0009
Total		**51.39**	**74.32**	**1.69**	**0.09**	**52.35**	**9.63**	**156.68**	**18.41**

- Remove three existing Waukesha L7042GL compressor engines (C1, C3, C4) and install two Caterpillar G3606 compressor engines.
- Project does not trigger PSD. Synthetic minor HAP source, therefore replacement Caterpillar engines not subject to 40 CFR 63, subpart ZZZZ, provided they are not "new" engines, as defined in the subpart.

Table 10 - Alternative Operating Scenario #3 – Summary of Potential Emissions BP Wolf Point Compressor Station

Emission Unit ID	Description	Controlled Emissions (tpy)						Uncontrolled Emissions (tpy)	
		NOx	CO	PM	SO_2	VOC	CH_2O	CO	CH_2O
G1	59 hp Kohler 50RZGB Gas Generator Set (GM 5.7 liter engine)	4.10	25.81	0.06	0.00	1.14	0.07	25.81	0.07
WP1	1895 hp Caterpillar G3606 Compressor Engine w/ Oxidation Catalyst	12.81	4.57	0.56	0.03	18.12	2.93	45.75	7.32
WP2	1895 hp Caterpillar G3606 Compressor Engine w/ Oxidation Catalyst	12.81	4.57	0.56	0.03	18.12	2.93	45.75	7.32
WP3	1895 hp Caterpillar G3606 Compressor Engine w/ Oxidation Catalyst	12.81	4.57	0.56	0.03	18.12	2.93	45.75	7.32
IEUs	Insignificant Emission Units	1.23	1.04	0.09	0.002	2.21	0.0009	1.04	0.0009
Total		**43.76**	**40.57**	**1.83**	**0.10**	**57.69**	**8.85**	**164.10**	**22.03**

- Remove fourth existing Waukesha L7042GL compressor engine (C1, C2, C3, or C4) and install third Caterpillar G3606 compressor engine.
- Minor modification of a minor PSD source. Remains a minor PSD source. Synthetic minor HAP source, therefore engines not subject to 40 CFR 63, subpart ZZZZ, provided they are not "new" engines, as defined in the subpart.

2. Establishment of Synthetic Minor Limits

a. Applicable PTE guidance

Under 40 CFR 52.21, "potential to emit" is defined as the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation, or the effect it would have on emissions, is federally enforceable. Potential to emit is meant to be a worse case emissions calculation. Actual emissions may be much lower.

National EPA guidance on PTE states that air pollution control equipment (in this case, the oxidation catalysts for WP1, WP2, and WP3 under Alternative Operating Scenarios #1a-#1c, #2, and #3) can be credited as restricting PTE only if federally enforceable requirements are in place requiring the use of such air pollution control equipment. (Reference: letter dated November 27, 1995, from David Solomon, Acting Group Leader, Integrated Implementation Group, Office of Air Quality Planning & Standards, U.S. EPA, to Timothy Mohin of Intel Government Affairs.) The primary applicable guidance is a memo titled, "Guidance on Limiting Potential to Emit in New Source Permitting," dated June 13, 1989, to EPA Regional Offices, from the Office of Enforcement and Compliance Monitoring (OECA), and the Office of Air Quality Planning & Standards (OAQPS). A later memo to the EPA Regional Offices, dated *January 25, 1995, titled "Guidance on Enforceability Requirements for Limiting Potential to* Emit through SIP and §112 Rules and General Permits," also provides guidance on this topic.

In consultation with Office of General Counsel at EPA Headquarters, as well as with EPA Regions IX and X, the EPA Region VIII office determined that authority exists under the CAA and 40 CFR 71 to create a restriction on potential to emit through issuance of a part 71 permit. The specific citations of authority are:

CAA Section 304(f)(4): provides that the term "emission limitation, standard of performance or emission standard" includes any other standard, limitation, or schedule established under any permit issued pursuant to title V ..., any permit term or condition, and any requirement to obtain a permit as a condition of operations.

40 CFR 71.6(b): provides that all terms and conditions in a part 71 permit, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Act.

40 CFR 71.7(e)(1)(i)(A)(4)(*i*): provides that a permit modification that seeks to establish a federally enforceable emissions cap assumed to avoid classification as a modification under any provision of title I of the CAA (which includes PSD), and for which there is no underlying applicable requirement, does not qualify as a minor permit modification. Under 40 CFR 71.7(e)(3)(i), it is therefore a significant permit modification, which, according to 40 CFR 71.7(e)(3)(ii), must meet all the requirements that would apply to initial permit issuance or permit renewal.

Hourly emissions limits for CO and CH_2O in pounds per hour are established in the permit as enforceable conditions for replacement units WP1, WP2, and WP3. The fitting of the engines with oxidation catalysts, along with work practice requirements, operational restrictions, and adequate testing, monitoring, reporting, and recordkeeping requirements have also been included as permit conditions to make the restrictions on potential emissions practically enforceable.

b. Components of the PTE restrictions

Potential Emissions: The current permit for the Wolf Point Compressor Station includes hourly emission limits as a component of the restriction on PTE for engines WP1, WP2, and WP3, along with certain related work practice and operational requirements, and adequate testing, monitoring, reporting, and recordkeeping requirements. The enforceable limits on the CO and CH_2O emissions for units WP1, WP2, and WP3 will reduce potential emissions to 40.57 tons per year and 8.85 tons per year, respectively. The draft renewal permit maintains these restrictions on PTE; however, because the engines are planned to be installed using a phased approach, the section of the permit describing specific requirements has been modified to include separate sections for the Current Operations and each of the Alternative Operating Scenarios.

Emission Limits: In response to BP's application request to make enforceable the use of the oxidation catalysts on engine units WP1, WP2, and WP3, emission limits for CO and CH_2O have been established in the permit, as well as work practice and operational requirements. BP requested emission limits of 1.04 pounds per hour of CO and 0.69 pounds per hour of CH_2O on each of the engines in order to avoid major HAP status for the facility.

Testing: In order to determine compliance with the established permit limits, requirements for reference method performance testing for CO and CH_2O are included as permit conditions. In addition, a requirement to conduct performance testing upon catalyst change out has been included.

Monitoring: Monitoring will be accomplished using a portable analyzer semi-annually to monitor for CO emissions, an annual performance test for CH_2O emissions, weekly temperature measurements to monitor the inlet temperatures of engine exhaust into the catalyst for each engine and monthly measurements of pressure drop across the catalyst. In order for the oxidation catalyst to effectively reduce CO and CH_2O emissions, the inlet temperature to the catalyst must be maintained at no less than 450°F and no more than 1350°F. Pressure drop is a good indication of catalyst operation; too low, the catalyst may be blown out; too high, the catalyst may be clogged. The pressure drop across the catalysts shall not change by more than two (2) inches of water at 100% load plus or minus 10% from the baseline pressure drop across the catalyst measured during the final performance test.

3. Tribe Information

a. Indian country

The BP Wolf Point Compressor Station is located within the exterior boundaries of the Southern Ute Indian Reservation and is thus within Indian country as defined at 18 U.S.C. §1151. The Southern Ute Tribe does not have a federally-approved Clean Air Act (CAA) title V operating permits program nor does EPA's approval of the State of Colorado's title V program extend to Indian country. Thus, EPA is the appropriate governmental entity to issue the title V permit to this facility.

b. The reservation

The Southern Ute Indian Reservation is located in Southwestern Colorado adjacent to the New Mexico boundary. Ignacio is the headquarters of the Southern Ute Tribe, and Durango is the closest major city, just 5 miles outside of the north boundary of the Reservation. Current information indicates that the population of the Tribe is about 1,305 people with approximately 410 tribal members living off the Reservation. In addition to Tribal members, there are over 30,000 non-Indians living within the exterior boundaries of the Southern Ute Reservation.

c. Tribal government

The Southern Ute Indian Tribe is governed by the Constitution of the Southern Ute Indian Tribe of the Southern Ute Indian Reservation, Colorado adopted on November 4, 1936 and subsequently amended and approved on October 1, 1975. The Southern Ute Indian Tribe is a federally recognized Tribe pursuant to Section 16 of the Indian Reorganization Act of June 18, 1934 (48 Stat.984), as amended by the Act of June 15, 1935 (49 Stat. 378). The governing body of the Southern Ute Indian Tribe is a seven member Tribal Council, with its members elected from the general membership of the Tribe through a yearly election process. Terms of the Tribal Council are three years and are staggered so in any given year 2 members are up for reelection. The Tribal Council officers consist of a Chairman, Vice-Chairman and Treasurer.

d. Local air quality and attainment status

The Tribe maintains an air monitoring network consisting of two sites equipped to collect Oxides of Nitrogen (NO_2), Ozone (O_3), Carbon Monoxide (CO) and meteorological data. The Tribe has collected NO_2 and O_3 data at the Ignacio site and Bondad site since June 1, 1982, and April 1, 1997, respectively. Since January 1, 2000, both sites initiated meteorological monitors measuring Wind Speed, Wind Direction, Vertical Wind Speed, Outdoor Temperature, Relative Humidity, Solar Radiation, and Rain/Snow Melt Precipitation. Particulate data (PM_{10}) was collected from December 1, 1981 to September 30, 2006, at the Ignacio site and since April 1, 1997 to September 30, 2006, at the Bondad site. The monitors indicate the following averages for the pollutant monitored: An annual average for NO_2, an hourly average for O_3 and CO, an 8-hour average for CO.

4. Applicable Requirements

a. <u>Applicable Requirement Review</u>

The following discussions address applicable requirements, and requirements that may appear to be applicable but are not. All applicable and non-applicable requirements addressed here are included in the Code of Federal Regulations, Title 40. In cases where applicability may appear to differ between the Current Operating Scenario and the Alternative Operating Scenarios, there is a separate applicability discussion for each scenario.

Chemical Accident Prevention Program

Based on BP's application, Wolf Point Compressor Station currently has no regulated substances above the threshold quantities in this rule and therefore are not subject to the requirement to develop and submit a risk management plan. BP has an ongoing responsibility to submit this plan <u>IF</u> a substance is listed that BP has in quantities over the threshold amount or <u>IF</u> BP ever increases the amount of any regulated substance above the threshold quantity.

Stratospheric Ozone and Climate Protection

<u>Air Conditioning Units</u>: Based on information supplied in BP's application, there are no air conditioning units at the Wolf Point Compressor Station. However, should BP perform any maintenance, service, repair, or disposal of any equipment containing chlorofluorocarbons (CFC's), or contracts with someone to do this work, BP would be required to comply with title VI of the Clean Air Act.

<u>Halon Fire Extinguishers</u>: Based on information supplied in BP's application, there are no halon fire extinguishers at the Wolf Point Compressor Station. However, should BP obtain any halon fire extinguishers, then it must comply with the standards of 40 CFR part 82, subpart H for halon emissions reduction, if it services, maintains, tests, repairs, or disposes of equipment that contains halons or uses such equipment during technician training. Specifically, BP would be required to comply with title IV of the Clean Air Act and 40 CFR part 82, subpart H and submit an application for a modification to this title V permit.

New Source Performance Standards (NSPS)

<u>40 CFR Part 60, Subpart A</u>: General Provisions. This subpart applies to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication of any standard in part 60. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 60.

As explained below, the Wolf Point Compressor Station is not subject to any specific subparts of part 60 under current operations and potentially under the proposed Alternative Operating Scenarios, therefore the General Provisions of part 60 do not apply under the Current Operating Scenario and potentially would not apply under the Alternative Operating Scenarios. **However, as also explained below, the Wolf Point Compressor Station may become subject**

to specific requirements of NSPS, subpart JJJJ under the proposed Alternative Operating Scenarios if the replacement engines are new or reconstructed, as defined in the subpart. In that case, the source would be subject to the General Provisions of part 60 and the replacement would require a minor modification to the permit to add applicable subpart A and subpart JJJJ requirements into the permit.

40 CFR Part 60, Subpart K: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. 40 CFR part 60, subpart K does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

The subpart does not apply to the storage vessels at the Wolf Point Compressor Station because there are no petroleum liquid storage tanks at this facility with capacity greater than 40,000 gallons that were constructed, reconstructed, or modified after June 11, 1973, and prior to May 19, 1978.

40 CFR Part 60, Subpart Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to June 23, 1984. This rule applies to storage vessels for petroleum liquids with a storage capacity greater than 40,000 gallons. Subpart Ka does not apply to petroleum storage vessels with a capacity of less than 420,000 gallons used for petroleum or condensate stored, processed, or treated prior to custody transfer.

This subpart does not apply to the storage vessels at the Wolf Point Compressor Station because there are no petroleum liquid storage tanks at this facility with capacity greater than 40,000 gallons that were constructed, reconstructed, or modified after May 18, 1978, and prior to June 23, 1984.

40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This rule applies to storage vessels with a capacity greater than or equal to 75 cubic meters storing volatile organic liquids.

This subpart does not apply to the storage vessels at the Wolf Point Compressor Station because the facility has no tanks greater than or equal to 75 cubic meters that store volatile organic liquids.

40 CFR Part 60, Subpart GG: Standards of Performance for Stationary Gas Turbines. This rule applies to stationary gas turbines, with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hr), that commenced construction, modification, or reconstruction after October 3, 1977.

There are no stationary gas turbines located at the Wolf Point Compressor Station; therefore, this subpart does not apply.

40 CFR Part 60, Subpart KKK: Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This rule applies to compressors and other equipment at onshore natural gas processing facilities. As defined in this subpart, a natural gas processing plant is any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids (NGLs) to natural gas products, or both. Natural gas liquids are defined as the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

The Wolf Point Compressor Station does not extract natural gas liquids from field gas, nor does it fractionate mixed NGLs to natural gas products, and thus does not meet the definition of a natural gas processing plant under this subpart. Therefore, this rule does not apply.

40 CFR Part 60, Subpart LLL: Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions. This rule applies to sweetening units and sulfur recovery units at onshore natural gas processing facilities. As defined in this subpart, sweetening units are process devices that separate hydrogen sulfide (H_2S) and carbon dioxide (CO_2) from a sour natural gas stream. Sulfur recovery units are defined as process devices that recover sulfur from the acid gas (consisting of H_2S and CO_2) removed by a sweetening unit.

There are no sweetening or sulfur recovery units at the Wolf Point Compressor Station. Therefore, this subpart does not apply.

40 CFR Part 60, Subpart KKKK: Standards of Performance for Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005. The rule applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour.

BP does not operate stationary combustion turbines at the Wolf Point Compressor Station. Therefore, this subpart does not apply.

40 CFR Part 60, Subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. This subpart establishes emission standards and compliance requirements for the control of emissions from stationary spark ignition (SI) internal combustion engines (ICE) that commenced construction, modification or reconstruction after June 12, 2006. According to the definitions in 40 CFR 60.2, "commence" means an owner or operator has undertaken, or entered into a contractual obligation to undertake within a reasonable time, a continuous program of construction or modification. "Construction" means fabrication, erection, or installation of an affected facility. "Modification" means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into that atmosphere not previously emitted. The rule applies to new, reconstructed, or modified stationary gasoline-fueled SI ICE, or any other type of ICE with a spark plug (or other type of sparking device) and with operating characteristics similar to the theoretical Otto combustion cycle. These include emergency and non-emergency stationary SI ICE of all horsepower ratings that burn gasoline, liquid petroleum gas, natural gas, and landfill/digester gas, with requirements differing based on the manufacturer dates, horsepower rating, fuel type, and emergency versus non-emergency operation.

All of the Waukesha L7042GL stationary spark ignition internal combustion engines and the generator currently operating at the Wolf Point Compressor Station (compressor engines C1 through C4, and generator G1) commenced construction, reconstruction, or modification prior to June 12, 2006. Therefore, this subpart does not apply under the Current Operating Scenario and would not apply under the Alternative Operating Scenarios if the replacement engines commence construction, reconstruction, or modification prior to June 12, 2006. **However, if any of the Caterpillar G3606 replacement compressor engines WP1 through WP3 installed during the replacement project commence construction, modification, or reconstruction on or after June 12, 2006, the replacement will require a minor modification to the permit (rather than a simple off permit change notification) so that conditions can be added to the permit to cover applicable general provisions of part 60, and specific applicable requirements of NSPS, subpart JJJJ.**

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Subpart A: General Provisions. This subpart contains national emissions standards for hazardous air pollutants (HAP) that regulate specific categories of sources that emit one or more HAP regulated pollutants under the Clean Air Act. The general provisions under subpart A apply to sources that are subject to the specific subparts of part 63.

As explained below, Wolf Point Compressor Station is not subject to any specific subparts of part 63 under the Current Operating Scenario, and potentially the proposed Alternative Operating Scenarios; therefore, the General Provisions of part 63 do not apply under the Current Operating Scenario and potentially would not apply under the proposed Alternative Operating Scenarios. However, under the Current Operating Scenario and potentially the proposed Alternative Operating Scenarios, the facility is a major or area HAP source (depending on the scenario) and operates engines greater than 500 hp that are affected units of 40 CFR 63, subpart ZZZZ (the RICE MACT). While these engines are not (or may not be) subject to the RICE MACT because they are existing units as defined in the subpart, pursuant to

§63.10(b)(3), BP must keep a record of the non-applicability for a period of five years or until conditions change at the facility causing the engines to become affected units. **As explained below, the Wolf Point Compressor Station may become subject to specific requirements of 40 CFR 63, subpart ZZZZ (the RICE MACT) under the proposed Alternative Operating Scenarios if the replacement engines are new or reconstructed, as defined in the subpart. In that case, the source would be subject to the General Provisions of part 63 and the replacement would require a minor modification to the permit to add applicable subpart A and subpart ZZZZ requirements into the permit.**

40 CFR Part 63, Subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. This subpart applies to the owners and operators of affected units located at natural gas production facilities that are major sources of HAP's, and that process, upgrade, or store natural gas prior to the point of custody transfer, or that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. The affected units are glycol dehydration units, storage vessels with the potential for flash emissions, and the group

of ancillary equipment, and compressors intended to operate in volatile hazardous air pollutant service, which are located at natural gas processing plants.

Throughput Exemption:

Those sources whose maximum natural gas throughput, as appropriately calculated in §63.760(a)(1)(i) through (a)(1)(iii), is less than 18,400 standard cubic meters per day are exempt from the requirements of this subpart.

Source Aggregation:

Major source, as used in this subpart, has the same meaning as in §63.2, except that:

1.) Emissions from any oil and gas production well with its associated equipment and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units.

2.) Emissions from processes, operations, or equipment that are not part of the same facility shall not be aggregated.

3.) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage tanks with flash emission potential shall be aggregated for a major source determination.

Facility:

For the purpose of a major source determination, facility means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in subpart HH. Examples of facilities in the oil and natural gas production category include, but are not limited to: well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Production Field Facility:

Production field facilities are those located prior to the point of custody transfer. The definition of custody transfer (40 CFR 63.761) means the point of transfer after the processing/treating in the producing operation, except for the case of a natural gas processing plant, in which case the point of custody transfer is the inlet to the plant.

Natural Gas Processing Plant:

A natural gas processing plant is defined in 40 CFR 63.761 as any processing site engaged in the extraction of NGL's from field gas, or the fractionation of mixed NGL's to natural gas products, or a combination of both. A treating plant or gas plant that does not engage in these activities is considered to be production field facility.

Major Source Determination for Production Field Facilities:

The definition of major source in this subpart (at 40 CFR 63.761) states, in part, that only emissions from the dehydration units and storage vessels with a potential for flash emissions at production field facilities are to be aggregated when comparing to the major source thresholds. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated.

Area Source Applicability:

40 CFR part 63, subpart HH applies to area sources of HAPs. An area source is a HAP source whose total HAP emissions are less than 10 tpy of any single HAP or 25 tpy for all HAPs in aggregate. This subpart requires different emission reduction requirements for triethylene glycol dehydration units found at oil and gas production facilities based on their geographical location. Units located in densely populated areas (determined by the Bureau of Census) and known as urbanized areas with an added 2-mile offset and urban clusters of 10,000 people or more, are required to have emission controls. Units located outside these areas will be required to have the glycol circulation pump rate optimized or operators can document that PTE of benzene is less than 1 tpy.

Applicability of subpart HH to the Wolf Point Compressor Station:

The Wolf Point Compressor Station does not engage in the extraction of NGL's and therefore is not considered a natural gas processing plant. Hence, the point of custody transfer, as defined in this subpart HH, occurs downstream of the station and the facility would therefore be considered a production field facility. For production field facilities, only emissions from the dehydration units and storage vessels with a potential for flash emissions are to be aggregated to determine major source status. The facility does not have flash tanks and the HAP emissions from the dehydration units alone at the facility are below the major source thresholds of 10 tons per year of a single HAP and 25 tons per year of aggregated HAPs.

With respect to the area source requirements of this subpart, the facility is located outside both an urban area and an urban cluster. Furthermore, uncontrolled benzene emissions from the one TEG glycol dehydrator unit at the facility was determined to be less than 1 tpy using GRI-GLYCalc Version 4.0, as presented in the supporting documentation in the application. **As a result, under any of the proposed Alternative Operating Scenarios, the dehydration unit at the facility is exempt from the §67.764(d) general requirements for area sources. However, the following general recordkeeping requirement does apply to this facility:**

- §63.774(d)(1) – retain the GRI-GLYCalc determinations used to demonstrate that actual average benzene emissions are below 1 tpy.

40 CFR Part 63, Subpart HHH: National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. This rule applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user, and that are a major source of hazardous air pollutant (HAP) emissions. Natural gas transmission means the pipelines used for long distance transport and storage vessel is a tank or other vessel designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon, liquids, produced water or other liquid and is constructed of wood, concrete, steel or plastic structural support.

This subpart does not apply to the Wolf Point Compressor Station, as the facility is a natural gas production facility and not a natural gas transmission or storage facility.

40 CFR Part 63, Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This rule establishes national emission limitations and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines (RICE). A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. This rule applies to owners or operators of new and reconstructed stationary RICE of any horsepower rating which are located at a major or area source of HAP. While all stationary RICE located at major or area sources are subject to the final rule (promulgated January 18, 2008, amending the final rule promulgated June 15, 2004), there are distinct requirements for regulated stationary RICE depending on their design, use, horsepower rating, fuel, and major or area HAP emission status. The standards in the final rule have specific requirements for most new or reconstructed RICE and for existing spark ignition (SI) 4 stroke rich burn (4SRB) stationary RICE. With the exception of the existing spark ignition 4SRB stationary RICE, other types of existing stationary RICE (i.e., SI 2 stroke lean burn (2SLB), SI 4 stroke lean burn (4SLB), compression ignition (CI), stationary RICE that combust landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, emergency, and limited use units) located at major and area sources of HAP emissions are not subject to any specific requirements under the final rule.

Major Source Applicability:

Per the definitions in 40 CFR 63.6590, a stationary RICE with a site rating of greater than 500 bhp is existing at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced before December 19, 2002. A stationary RICE with a site rating of less than or equal to 500 bhp is existing at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced before June 12, 2006. A stationary RICE with a site rating of greater than 500 bhp is new at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced on or after December 19, 2002. A stationary RICE with a site rating of less than or equal to 500 bhp is new at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced on or after June 12, 2006.

Current Operating Scenario: The Wolf Point Compressor Station under current operations is a major source of HAP emissions, as defined in subpart ZZZZ. However, the subpart does not apply, because all four Waukesha L7042GL compressor engines are considered existing 4SLB stationary RICE with a site rating of greater than 500 bhp for the following reasons: (1) the engines were constructed and installed at the facility prior to December 19, 2002 (C3 and G1), or (2) the engines were operated at another facility prior to December 19, 2002, were disassembled and removed from the previous facility, were installed at the Wolf Point Compressor Station after December 19, 2002, and do not meet the definition of reconstruction in 40 CFR 63.2 and condition V.Q.7.(d)(ii)(B)(1) of the draft permit (C1, C2, and C4), because the cost of any engine overhaul was less than 50% of the cost to replace the RICE currently operating at the Wolf Point Compressor Station.

Area Source Applicability:

Per the definitions in 40 CFR 63.6590 a stationary RICE is existing at an area source of HAP emissions if construction or reconstruction of the unit commenced before June 12, 2006. A stationary RICE is new at a major source of HAP emissions if construction or reconstruction (as defined in §63.2) of the unit commenced on or after June 12, 2006.

Alternative Operating Scenarios #1a-1c, #2, and #3: When accounting for federally enforceable engine emission controls, the Wolf Point Compressor Station under any of the Alternative Operating Scenarios would be a synthetic minor, or area source of HAP emissions (as defined in subpart ZZZZ). If the Caterpillar G3606 replacement compressor engines commenced construction or reconstruction (as defined in §63.2) before June 12, 2006, then the engines would not be subject to any specific requirements in the subpart. **However, if the Caterpillar G3606 replacement compressor engines commenced construction on or after June 12, 2006, the engines will be subject to specific requirements in the RICE MACT (as well as NSPS subpart JJJJ, which the RICE MACT refers to for SI RICE at area sources, and the General Provisions in subpart A), and the replacement will require a minor permit modification to add those requirements into the permit.**

Compliance Assurance Monitoring (CAM) Rule

The CAM rule applies to each Pollutant Specific Emission Unit (PSEU) that meets a three-part test. The PSEU must 1) be subject to an emission limitation or standard, and 2) use a control device to achieve compliance, and 3) have pre-control emissions that exceed or are equivalent to the major source threshold.

Wolf Point Compressor Station is subject to emission limits for CO and CH_2O for specific compressor engines. Three engines (WP1, WP2, and WP3) that would operate at the site in different configurations under proposed Alternative Operating Scenarios #1a-1c, #2, and #3, are subject to a control requirement of oxidation catalysts. The engines with controls meet the requirements for applicability of CAM for the CO and CH_2O emissions. However, according to 40 CFR 64.2(b)(1)(vi), CAM requirements do not apply to any emission unit that is subject to an emission limit or standard for which an applicable requirement specifies a continuous compliance determination method. The draft part 71 renewal permit for these controlled engines requires demonstrations through semi-annual performance testing for CO and annual performance testing for CH_2O emissions using a portable analyzer, a monitoring protocol approved by EPA, and EPA Reference test methods. In addition, periodic parametric monitoring and maintenance activities (see sections II. and III., and IV. of the draft part 71 renewal permit) are required. Parametric measurements include differential pressure and temperature across the catalytic converter. These draft permit conditions are sufficient to provide reasonable assurance of continuous compliance and allow BP to make an informed certification of compliance.

b. <u>Conclusion</u>

Based on the information provided in BP's application for the Wolf Point Compressor Station, this source is subject to those existing applicable Federal CAA programs discussed above. The Wolf Point Compressor Station is not subject to any implementation plan such as exists within state jurisdictions. Therefore, the Wolf Point Compressor Station is not subject to any other substantive requirements that control their emissions under the CAA.

EPA recognizes that, in some cases, sources of air pollution located in Indian country are subject to fewer requirements than similar sources located on land under the jurisdiction of a state or local air pollution control agency. To address this regulatory gap, EPA is in the process of developing national regulatory programs for preconstruction review of major sources in non-attainment areas and of minor sources in both attainment and non-attainment areas. These programs will establish, where appropriate, control requirements for sources that would be incorporated into part 71 permits. To establish additional applicable, federally-enforceable emission limits, EPA Regional Offices will, as necessary and appropriate, promulgate Federal Implementation Plans (FIPs) that will establish Federal requirements for sources in specific areas. EPA will establish priorities for its direct Federal implementation activities by addressing as its highest priority the most serious threats to public health and the environment in Indian country that are not otherwise being adequately addressed.

Further, EPA encourages and will work closely with all tribes wishing to develop Tribal Implementation Plans (TIPs) for approval under the Tribal Authority Rule. EPA intends that its Federal regulations created through a FIP will apply only in those situations in which a tribe does not have an approved TIP.

5. EPA Authority

a. General authority to issue part 71 permits

Title V of the Clean Air Act requires that EPA promulgate, administer, and enforce a Federal operating permits program when a state does not submit an approvable program within the time frame set by title V or does not adequately administer and enforce its EPA-approved program. On July 1, 1996 (61 FR 34202), EPA adopted regulations codified at 40 CFR part 71 setting forth the procedures and terms under which the Agency would administer a Federal operating permits program. These regulations were updated on February 19, 1999 (64 FR 8247) to incorporate EPA's approach for issuing Federal operating permits to stationary sources in Indian country.

As described in 40 CFR 71.4(a), EPA will implement a part 71 program in areas where a state, local, or tribal agency has not developed an approved part 70 program. Unlike states, Indian tribes are not required to develop operating permits programs, though EPA encourages tribes to do so. See, e.g., Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the "Tribal Authority Rule"). Therefore, within Indian country, EPA will administer and enforce a part 71 Federal operating permits program for stationary sources until a tribe receives approval to administer their own operating permits program.

6. Use of All Credible Evidence

Determinations of deviations, continuous or intermittent compliance status, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit; other credible evidence (including any evidence admissible under the Federal Rules of Evidence) must be considered by the source and EPA in such determinations.

7. Public Participation

a. Public notice

As described in 40 CFR 71.11(a)(5), all part 71 draft operating permits shall be publicly noticed and made available for public comment. The Public Notice of permit actions and public comment period is described in 40 CFR 71(d).

There will be a 30 day public comment period for actions pertaining to a draft permit. Public notice will be given for this draft permit by mailing a copy of the notice to the permit applicant, the affected state, tribal and local air pollution control agencies, the city and county executives, the state and Federal land managers and the local emergency planning authorities which have jurisdiction over the area where the source is located. A copy of the notice will be provided to all persons who have submitted a written request to be included on the mailing list. If you would like to be added to our mailing list to be informed of future actions on these or other Clean Air Act permits issued in Indian country, please send your name and address to the contact listed below:

Claudia Smith, Part 71 Permit Contact
U.S. Environmental Protection Agency, Region 8
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202

Public notice will be published in the Durango Herald on the date specified in the cover letter to this document, giving opportunity for public comment on the draft permit and the opportunity to request a public hearing.

b. Opportunity for Comment

Members of the public are given an opportunity to review a copy of the draft permit prepared by EPA, the application, this Statement of Basis for the draft permit, and all supporting materials for the draft permit. Copies of these documents are available at:

La Plata County Clerk's Office
1060 East 2nd Avenue
Durango, Colorado 81302

and

Southern Ute Indian Tribe
Environmental Programs Office
116 Mouache Drive
Ignacio, Colorado 81137

and

U.S. EPA Region 8
Air Program Office
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202

All documents are available for review at the U.S. EPA Region 8 office Monday through Friday from 8:00 a.m. to 4:00 p.m. (excluding Federal holidays).

Any interested person may submit written comments on the draft part 71 operating permit during the public comment period to the Part 71 Permit Contact at the address listed above. All comments will be considered and answered by EPA in making the final decision on the permit. EPA keeps a record of the commentors and of the issues raised during the public participation process.

Anyone, including the applicant, who believes any condition of the draft permit is inappropriate should raise all reasonable ascertainable issues and submit all arguments supporting their position by the close of the public comment period. Any supporting materials submitted must be included in full and may not be incorporated by reference, unless the material has been already submitted as part of the administrative record in the same proceeding or consists of state or Federal statutes and regulations, EPA documents of general applicability, or other generally available reference material.

c. Opportunity to Request a Hearing

A person may submit a written request for a public hearing to the Part 71 Permit Contact, at the address listed above, by stating the nature of the issues to be raised at the public hearing. Based on the number of hearing requests received, EPA will hold a public hearing whenever it finds there is a significant degree of public interest in a draft operating permit. EPA will provide public notice of the public hearing. If a public hearing is held, any person may submit oral or written statements and data concerning the draft permit.

d. Appeal of permits

Within 30 days after the issuance of a final permit decision, any person who filed comments on the draft permit or participated in the public hearing may petition to the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments or participate in the public hearing may petition for administrative review, only if the changes from the draft to the final permit decision or other new grounds were not reasonably foreseeable during the public comment period. The 30 day period to appeal a permit begins with EPA's service of the notice of the final permit decision.

The petition to appeal a permit must include a statement of the reasons supporting the review, a demonstration that any issues were raised during the public comment period, a demonstration that it was impracticable to raise the objections within the public comment period, or that the grounds for such objections arose after such a period. When appropriate, the petition may include a showing that the condition in question is based on a finding of fact or conclusion of law which is clearly erroneous; or, an exercise of discretion, or an important policy consideration which the Environmental Appeals Board should review.

The Environmental Appeals Board will issue an order either granting or denying the petition for review, within a reasonable time following the filing of the petition. Public notice of the grant of review will establish a briefing schedule for the appeal and state that any interested person may file an amicus brief. Notice of denial of review will be sent only to the permit applicant and to the person requesting the review. To the extent review is denied, the conditions of the final permit decision become final agency action.

A motion to reconsider a final order shall be filed within 10 days after the service of the final order. Every motion must set forth the matters claimed to have been erroneously decided and the nature of the alleged errors. Motions for reconsideration shall be directed to the Administrator rather than the Environmental Appeals Board. A motion for reconsideration shall not stay the effective date of the final order unless it is specifically ordered by the Board.

e. Petition to reopen a permit for cause

Any interested person may petition EPA to reopen a permit for cause, and EPA may commence a permit reopening on its own initiative. EPA will only revise, revoke and reissue, or terminate a permit for the reasons specified in 40 CFR 71.7(f) or 71.6(a)(6)(i). All requests must be in writing and must contain facts or reasons supporting the request. If EPA decides the request is not justified, it will send the requester a brief written response giving a reason for the decision. Denial of these requests is not subject to public notice, comment, or hearings. Denials can be informally appealed to the Environmental Appeals Board by a letter briefly setting forth the relevant facts.

f. Notice to affected states/tribes

As described in 40 CFR 71.11(d)(3)(i), public notice will be given by mailing a copy of the notice to the air pollution control agencies of affected states, tribal and local air pollution control agencies which have jurisdiction over the area in which the source is located, the chief executives of the city and county where the source is located, any comprehensive regional land use planning agency and any state or Federal land manager whose lands may be affected by emissions from the source. The following entities will be notified:

State of Colorado, Department of Public Health and Environment
State of New Mexico, Environment Department
Southern Ute Indian Tribe, Environmental Programs Office
Ute Mountain Ute Tribe, Environmental Programs
Navajo Tribe, Navajo Nation EPA
Jicarilla Tribe, Environmental Protection Office
La Plata County, County Clerk
Town of Ignacio, Mayor
National Park Service, Air, Denver, CO
U.S. Department of Agriculture, Forest Service, Rocky Mountain Region
Carl Weston
San Juan Citizen Alliance
Rocky Mountain Clean Air Action

EXHIBIT 8

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Jack Vaughn, EnerVest San Juan Operating Co. (July 8, 1999)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

JUL 8 1999

Ref: 8P-AR

Jack Vaughn
EnerVest San Juan Operating Co.
570 B Turner Dr.
Durango, CO 81301

Dear Mr. Vaughn,

This letter is in response to your letter dated June 3, 1999 requesting clarification of the aggregation of sources for the purpose of determining Title V applicability as it applies to pipeline compressor stations. More specifically, you have asked us to determine whether we consider each emitting unit at each compressor station to be a single source or all of the emitting units at each compressor station in aggregate to be a single source for Title V permitting purposes, and whether these sources are major.

In the Code of Federal Regulations at 40 CFR 71.2 the definition of "major source" states, in part:

> "Major source means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping....."

We interpret this to mean that each compressor station with its associated emitting units (e.g. compressor engines, wells, pumps, dehydrators, storage and transmission tanks, etc...) comprises a 'group of stationary sources" and would be considered a single source for purposes of determining Title V applicability.

With this interpretation in mind, the additional information you provided to us in the letter, and further telephone conversations with you, we have determined that the EnerVest San Juan Operating Co. has five sources (compressor stations with their associated emitting units) located within the exterior boundaries of the Southern Ute Indian Reservation in southwest Colorado. The following table illustrates the sources.

1	Blackridge Compressor Station (BR SU 8-2) SW NW Sec. 8 T33N - R10W
2	Valencia Canyon Compressor Station (VC SU 32-1) SW SE Sec. 32 T33N - R11W
3	Valencia Canyon Compressor Station (VC SU 32-4) NW NE Sec. 32 T33N - R11W
4	Valencia Canyon Compressor Station (VC SU 20-4) SE NE Sec. 20 T33N - R11W
5	Indian Creek Compressor Station (IC SU 24-4) NW SW Sec. 24 T34N - R10W

To further determine whether these are major sources for purposes of Title V permitting, we require additional information. Specifically, for each source identified above we are requesting:

- A list of all emission units for each source such as compressor engines, wells, pumps, heaters, dehydrators, tanks, emergency engines, etc.
- The date of construction and installation of all the listed equipment.
- The potential to emit of all criteria pollutants (including VOCs) and all hazardous air pollutants for each emission unit.
- A copy of any existing air pollution permits that may have been issued by the State of Colorado.

We hope that this has clarified for you our understanding of the regulations as they pertain to the EnerVest San Juan Operating Company's facilities. If you have any further questions, please feel free to contact Kathleen Paser of my Technical Assistance staff at 303-312-6526.

Sincerely,

Richard R. Long, Director
Air and Radiation Program

cc:
Cheryl Wiescamp, Director of Environmental Programs, Southern Ute Indian Tribe
Virgil Frazier, Air Program Coordinator, Southern Ute Indian Tribe

EXHIBIT 9

Letter from Richard R. Long, Region VIII Director, Air Program, to Lynn R. Menlove, Manager, New Source Review Section, Division of Air Quality, Utah Department of Environmental Quality (August 8, 1997)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 500
DENVER, CO 80202-2466
http://www.epa.gov/region08

August 8, 1997

Ref: 8P2-A

Lynn R. Menlove, Manager
New Source Review Section
Division of Air Quality
Utah Department of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Dear Mr. Menlove:

This letter is in response to your letter dated May 23, 1997, about Great Salt Lake Minerals and whether their operations should be considered a single source or two sources under the Prevention of Significant Deterioration of Air Quality (PSD) regulations. We also received a letter from Mr. Jim Wolf with the Harris Chemical Group, dated June 30, 1997, that contained the June 16, 1997 letter that was sent to Utah, which discussed these issues about the Great Salt Lake Minerals plant.

After reviewing the information submitted and previous applicability determinations that have been made regarding the definition of stationary sources, we feel compelled to recommend that the subject pump station be considered part of the Great Salt Lake Minerals plant as a single source, despite the fact that the pump station is on one side of the Great Salt Lake while the production operations are on the other side of the lake. The underlying facts indicate that the pump station operates solely as a support facility to the plant. Guidance in the Standard Industrial Classification (SIC) Manual (Appendix B) states that the SIC code is a system for classifying establishments by type of economic activity. Each establishment is classified according to its primary activity. The pump station activity does not have its own primary economic activity but only supports the activity of the main facility. As such, we believe it would be incorrect to consider the pump station operation as a separate source.

The letter from Mr. Wolf contained a statement that said "The pump station merely supports brine transfer activities and has no production function or potential." The very fact that the pump station provides support to the production activities of the plant by brine transfer clearly provides justification that the pump station acts as a support facility to the plant. To our general knowledge, previous determinations, which have been made by EPA and states, have always determined that activities which support the primary activities of a source are considered to be part of the source to which they provide support. Distance between the operations is not nearly as important in determining if the operations are part of the same source as the possible support that one operation provides for another. We believe that Utah has at least one example of this in your definition of a source at Kennecott Copper, where the Bingham Canyon Mine and the Copperton Concentrator are considered to be one source connected by a slurry pipeline. The only written national guidance found in the New Source Review Guidance Notebook was numbered 3.18, dated 6/30/81, which dealt with two operations, separated one mile apart, that had a dedicated railroad line between them, and together produced one line of automobiles. The resulting determination was that they are one source.

We have coordinated our response with EPA New Source Review contacts in North Carolina and they agree that our guidance regarding this determination is consistent with statements that EPA has made about long-line operations, such as a pipeline or electrical power lines. EPA would not treat all of the pumping stations along a multi-state pipeline as one source. The distance between those types of operations is typically hundreds of miles. The supply of electrical power to a source has never been used to determine that separate operations are part of the same source. However, the physical relationship between the pump station and the production operations at the Great Salt Lake Minerals plant (i.e., a channel or "pipeline" across the bottom of the lake) is much more similar to conveying operations that transport raw materials to a processing plant. This clearly supports the production operation and is routinely considered to be part of a single stationary source (the production facility plus support operations). This is a rather unique (one of a kind) operation and our guidance is specific for this unique operation.

The only issue, really is the distance between the two operations. EPA did make a statement in the preamble to the August 7, 1980 PSD rules that if two operations were 20 miles apart, they would be too far apart to be considered one source. The rest of the determination was that because the two operations had different SIC codes, they would be separate sources. Our belief that the unique operations at the Great Salt Lake Minerals plant should be considered a single source is somewhat in conflict with the single statement that a 20-mile separation is too far apart to consider two operations as a single source. However, this distance was not established as a fixed requirement and involved facilities with different SIC codes, unlike The Great Salt Lake Minerals case. It remains our opinion that because of the unique relationship between the pump station and the salt processing plant and the dedicated channel (21.5 miles) between the two that supplies the pre-concentrated brine, the distance between the operations is not an overriding factor that would prevent them from being considered a single source.

Our position on this rather unique situation is only provided as guidance, as it remains the State's primary responsibility to make the final determination under your SIP-approved PSD regulations. I hope this is the information that you needed. If you have questions about our determination, please contact John Dale at (303) 312-6934.

Sincerely,

Richard R. Long, Director
Air Program

EXHIBIT 10

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Jeffrey L. Ingerson, Senior Environmental Specialist, Questar Gas Management Company (August 7, 1998)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 500
DENVER, CO 80202-2466

AUG - 7 1998

Ref: 8P-AR

Mr. Jeffrey L. Ingerson
Senior Environmental Specialist
Questar Gas Management Company
P.O. Box 45601
Salt Lake City, Utah 84145-0601

Dear Mr. Ingerson:

This is in response to your request for a decision concerning whether the operation of compressor units located at the Fidlar Station on the Uintah/Ouray Indian Reservation in Utah should be considered a single stationary source or two sources. Specifically, Questar Gas Management Company (QGMC) is asserting that based on different operational functions and separate organizational management, that the QGMC and Questar Pipeline Company (QPC) compressor units should constitute separate entities and should not be grouped together for purposes of permitting under the Prevention of Significant Deterioration (PSD) program. Furthermore, QGMC would like a determination as to the minimum distance required from the Fidlar Station site to make any new compression equipment a separate facility.

Upon review of the management and organizational function information that was submitted with your request and based on past applicability determinations that have been made regarding the PSD regulation definition of stationary source (40 CFR §52.21), EPA determines that all emissions units currently located at the Fidlar Station are considered one stationary source. (See enclosure your 6/17/98 request for the list of emissions units.)

Enclosed is a single source determination (dated 11/3/86) that was made for Valero Transmission Company whose major SIC code is 49 and Valero Gathering Company whose major SIC code is 13. This single source determination is applicable to the situation you have described at the Fidlar Station between QGMC and QPC. In reviewing the PSD requirements, each stationary source is to be classified according to its primary activity which is determined by its principal product or group of products. Thus, one source classification encompasses both primary and support facilities, even when it includes units with a different two-digit SIC code. In other words, support activities are aggregated with their associated primary activity regardless of dissimilar SIC codes. Even though QGMC and QPC are classified differently in the SIC manual (QGMC is SIC 13 and QPC is SIC 49), QPC is a support facility to QGMC because Questar Pipeline Company is the only means by which Questar Gas Management Company can introduce

AUG 1 4 1998

its natural gas product into commerce. Therefore, all emissions units at the Fidlar Station are considered one stationary source.

As to your question of what is the minimum distance between units to consider the units as separate facilities, EPA has not established a specific distance between pollutant emitting activities for determining when facilities should be considered separate or one source for permitting under the PSD program. Whether facilities are contiguous or adjacent is determined on a case-by-case basis, based on the relationship between the facilities. EPA has made single source determinations based on pollutant emitting activities located one mile apart to activities located six miles apart. (In another case, the activities were on opposite sides of a lake, which was over twenty miles across.) Distance between operations is not nearly as important in determining if the operations are part of the same source as the possible support that one operation provides for another. However, EPA does not intend for a "source" to include activities along a long-line operation; such as, pumping stations along a multi-state pipeline would not be considered a single stationary source. See 45 FR 52695 (August 7, 1980)

Aside from your questions on adjacency and ownership, the emissions data you submitted with your request and your July 28, 1998 conversation with Monica Morales of my staff indicates that your proposed modification would not be subject to major source permitting under the PSD program. You told Ms. Morales that the additional compressor unit you are proposing as a modification would have potential emissions less than 45 tons per year of NO_x. Currently, the emissions data you submitted show potential NO_x emissions without enforceable controls of about 248 tons per year. (Potential emissions are based on 8760 hours of operation per year.) This is below the 250 tons per year major source threshold, meaning the Fidlar Station is considered a minor source under the PSD permitting program.

A future modification to the present day Fidlar Station would be subject to PSD, if and only if, the modification in and of itself equaled or exceeded the 250 tons per year major source threshold. In other words, Questar could add 249 additional tons per year of a PSD pollutant and not be subject to the permitting requirements of PSD. ~~However, once the Fidlar Station is a major stationary source (i.e. emissions of any one pollutant exceeds 250 tons per year) any modification in which the net emissions increase exceeds the pollutant significant levels as defined in 40 CFR §52.21(b)(23)(i) would be subject to PSD.~~ Your proposed emissions increase of less than 45 tons per year would not be subject to PSD because the Fidlar Station is a minor source and the emissions increase would not exceed 250 tons per year. However, future modifications beyond your current proposal that exceed the significant emissions levels would be subject to PSD.

40 TPY NOx
100 TPY CO

See pg. 3
Permit Applic
PTE NOx = 316 TPY
CO = 267 TPY

Please submit to EPA in writing the specifics of all modifications and all future proposed modifications that are made to the Fidlar Station. Also, please copy Elaine Willie of the Ute Indian Tribe on all future correspondence to EPA pertaining to this source. If you have any questions concerning this determination or the clarification of the PSD regulations, you may contact Monica Morales with my staff at (303) 312-6936.

Sincerely,

Richard R. Long, Director
Air and Radiation Program

Enclosure

cc: Elaine Willie (Ute Indian Tribe)
Ed Kurip (Ute Indian Tribe)
Lynn Menlove (UT DAQ)

EXHIBIT 11

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program, to Dennis Myers, Construction Permit Unit Leader, Stationary Sources Program, Air Pollution Control Division, Colorado Department of Public Health and Environment (April 20, 1999)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 500
DENVER, CO 80202-2466

April 20, 1999

Ref: 8P-AR

Mr. Dennis Myers, P.E.
Construction Permit Unit Leader
Stationary Sources Program
Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South, APCD-SS-B1
Denver, CO 80246-1530

Dear Dennis,

EPA Region 8 has reviewed the proposed PSD construction permits for the American Soda Commercial Mine (Piceance facility) and processing plant (Parachute facility), which were sent to the EPA Region 8 office on March 17, 1999. We have identified two problems with this permit action: the first related to the State's determination that these are two separate sources for PSD permitting, and the second with the estimation and monitoring of VOC emissions. In addition, we are aware of the procedural and BACT issues raised by the National Park Service in its April 12, 1999, comment letter, and welcome the opportunity to discuss those concerns also.

Single vs. Separate Source

We have reviewed the information that American Soda's contractor, Steigers Corporation, provided via fax transmittal on April 13, 1999. That fax contained an October 9, 1998, 5 page letter from Hal Copeland to you, and your October 22, 1998, response. We have examined the State's determination that the mine and processing plant are separate sources for purposes of PSD permitting, and did not find any explanation for that decision. Since the mine and processing plant are planned to be roughly 35-40 miles apart (straight-line distance; connected by a 44 mile long pipeline), we surmise that the State is treating them as separate sources primarily due to distance (i.e., not "adjacent"). EPA Regional offices, in consultation with EPA Headquarters, have written several comment letters explaining that whether two facilities are "adjacent" is based on the "common sense" notion of a source and the functional inter-relationship of the facilities, and is not simply a matter of the physical distance between two facilities. I have enclosed the EPA comment letters for your further consideration.

In the case of American Soda's Piceance and Parachute facilities, we believe that EPA's policy holds that these facilities need to be considered as a single stationary source. The two clearly will be functionally interdependent, as evidenced by the dedicated slurry pipeline and the spent brine return pipeline which will connect the two facilities. Additional evidence is that one facility (the mine) is to produce an intermediate product for processing at the other facility (the processing plant). Given the integral connectedness of these facilities, we believe that the distance alone does not preclude these two being considered adjacent for PSD permitting purposes.

VOC emission estimation and monitoring

We are concerned with potential variability of VOC emissions from the solution mining process. VOC's are evolved from this process by dissolving into the hot water solution as it passes through the mineral deposits. American Soda's permit application stated: "injection fluid temperatures will generally be between 300° and 420°F, and the returned production fluid temperature will generally be 50° to 125°F less because energy is lost in the mining process." Over these temperature ranges, there are likely to be variations resulting from increased solubility of VOC contaminants evolved from the oil shale deposits as water temperatures rise. Similarly, we expect that there may be variations over the life of each solution mining well (as fluid injection pressures and flow rates change, as well as changes to the mineral deposit as it is depleted), and also due to physical location throughout the mineral deposits.

While we understand that the source has test data supporting its estimated emissions, we are still concerned. Thus, we encourage the department to exercise due diligence in following-up on the requirement that American Soda regularly test for VOC emissions (condition 16 of Piceance facility permit). Furthermore, it is very important to ensure that such testing is done under normal operating conditions. Thus, it would be prudent for the source to track water injection temperature and pressure, well-head brine temperature, flow rates, and other parameters that would provide adequate justification that its quarterly (or adjusted frequency) testing is consistent with ongoing operations at the facility. Finally, we recommend that the State scrutinize the sampling location and techniques employed in the source's testing protocols to ensure that all VOC emissions will be adequately quantified. In the event that actual VOC emissions are found to exceed the 40 tpy threshold, American Soda would need to address appropriate PSD permitting requirements, including BACT controls for its VOC emission points, as if construction had not yet commenced.

We look forward to assisting you with these issues. Please contact me at (303)312-6005 or Meredith Bond of my staff at (303)312-6438.

Sincerely,
Original signed by:

Richard R. Long, Director
Air and Radiation Program

Enclosures

January, 15, 1999, EPA Region 3 letter to John Slade, Pennsylvania DEP
May 21, 1998, EPA Region 8 letter to Lynn Menlove, Utah DAQ
August 8, 1997, EPA Region 8 letter to Lynn Menlove, Utah DAQ
August 7, 1997, EPA Region 10 letter to Andy Ginsberg, Oregon DEQ
August 27, 1996, memo from Robert Kellam, OAQPS/ITPID to Richard Long, Region 8
March 13, 1998, EPA Region 5 letter to Donald Sutton, Illinois EPA

cc: Ram Seetharam, CDPHE-APCD
Tom Gibbons, Steigers Corporation

bcc: Michele Dubow, EPA/OAQPS/MD-12
Cindy Reynolds, 8ENF-T

EXHIBIT 12

Memo from Steven Rothblatt, Region V Chief, Air Programs Branch to Edward E. Reich, Director, Stationary Source Enforcement Division (June 8, 1981)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

DATE: JUN 8, 1981

SUBJECT: Defining Two Separate Plants as One Source

FROM: Steve Rothblatt, Chief
Air Programs Branch

TO: Edward E. Reich, Director
Stationary Source Enforcement Division, (E341)

Region V has been asked by the State of Michigan and the General Motors Corporation to make a determination as to whether or not two plants on different sites constitute a single source. The purpose of this memo is to describe the circumstances related to this request and seek your counsel before we respond to the State and GM. We request your recommendation on our tentative position by June 12, 1981 at which time we will be responding to the State.

During the assembly of some vehicles in Lansing, Michigan, auto bodies are made in the Fisher Body plant and then are transported by truck to an Oldsmobile plant one mile away. At the Olds plant the bodies are placed on frames and the fenders and hoods are attached. At the present time the bodies are painted at the first location and the fenders and hoods are painted at the second location. GM is proposing to move the painting operations to one of the locations.

Under the present definition of source in nonattainment areas, GM would have to meet the Part D new source review requirements. However, under the March 12, 1981 proposed definition of source, the curtailment of painting at one place in a source could be used to offset additional painting elsewhere in the source and thus the source would avoid the Federal new source review requirements. The issue of concern for GM is whether or not these two plants which are separated by approximately 4,500 feet can be considered as one source.

Our investigation has revealed that both plants come under the same SIC code. Additionally, the two plants are the only facilities served by a special spur of the C&O Railroad for raw material delivery and in the future the spur will be used to move unpainted parts from one plant to another when the painting is done at one location. Furthermore, at other locations in the State where vehicles are assembled in this two step body/frame fashion, the two plants are under one roof or are connected by a conveyor for transporting the bodies.

It is our opinion that these Lansing plants are functionally equivalent to a source and that U.S. EPA has the flexibility to arrive at that conclusion. The Federal Register of August 7, 1980 on page 52695 states the following when discussing proximity of PSD activities "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." With the distance between the two plants less than one mile and the plants being connected by a railroad used only for GM, we believe that the plants meet the requirement of being adjacent and therefore can be considered one source.

Such an interpretation appears to be consistent with U.S. EPA's position which appears in the March Federal Register on page 16281. This position as stated, when supporting the change in "source" definition, is "even outside of these 'construction moratorium' areas under the present regulatory scheme, the August 7 definition can act as a disincentive to new investment and modernization by discouraging modifications to existing facilities."

We have concluded that should the March 12, 1981 proposed definition of source become final, the State under the existing SIP though a variance from the Commission will be able to issue a State permit to GM. The State will also require a phased in LAER by 1986. Thus, the environmental costs of this interpretation will be negligible.

Please contact Ronald J. Van Mersbergen at FTS 886-6056 for further information.

cc: E. Smith
M. Trutna

EXHIBIT 13

Memo from William B. Hathaway, Region VI Director, Air, Pesticides and Toxics Division to Allen Eli Bell, Executive Director, Texas Air Control Board (November 3, 1986)

Nov 03, 1986

Mr. Allen Eli Bell
Executive Director
Texas Air Control Board
6330 Highway 290 East
Austin, Texas 78723

Re: PSD Applicability Request, Valero Transmission Company Yoakum, DeWitt County, Texas

Dear Mr. Bell:

We have reviewed Valero Transmission Company's request for an applicability determination of Prevention of Significant Deterioration (PSD) permit requirements to the expansion at their Gohlke Plant in DeWitt County, Texas. At issue is whether the relationship between Valero Transmission Company, as a service provider under the SIC major code 49, to Valero Gathering Company under SIC major code 13 is such that there are two distinct PSD sources here.

Valero asserts that its gathering company is a separate company from its transmission company. Valero Gathering Company processes the gas from wells to remove hydrogen sulfide, carbon dioxide, and water to meet pipeline specifications prior to custody transfer to Valero Transmission Company. The principal product of Valero Gathering Company is pipeline quality natural gas under the SIC major code 13, while the principal product of Valero Transmission Company is the distribution of natural gas through a pipeline system under the SIC major code 49. Valero maintains that the Gathering Company does not convey, store, or otherwise assist in the production of Valero Transmission's principal product, and therefore concludes that the two companies are separate sources for the purpose of PSD applicability. For similar reasons, Valero maintains that Valero Hydrocarbon Company, an extraction facility in close proximity to Valero Transmission Company with an SIC major code 13, is a separate source from Valero Transmission Company.

In reviewing the PSD requirements, it is evident that each source is to be classified according to its primary activity which is determined by its principal product or group of products. Thus, one source classification encompasses both primary and support facilities, even if it includes units with different two digit SIC codes. Support facilities are typically those which convey, store, or otherwise assist in the production of the principal product or group of products produced or distributed, or services rendered. See 45 FR 52695 (August 7, 1980).

6T-EN	6T-E	6C-T
ASCENZI	HEPOLA	GREENFIELD

At issue is whether Valero Transmission Company is a support facility to Valero Gathering Company. A review of the activities of the two companies indicates that both companies produce natural gas as their principal product. We consider Valero Transmission Company as a support facility to Valero Gathering Company since the Transmission Company receives the processed natural gas from Valero Gathering Company and compresses it for distribution into a pipeline system. Thus, Valero Transmission Company is a support facility to Valero Gathering in that it conveys the product natural gas from the processing plant into the pipeline system. Available information further indicates that conveyance of the product natural gas through the Transmission Company is the only means of introducing the product natural gas into commerce. The Gathering Company is not equipped to introduce its product into commerce by any means other than through the Transmission Company. Consequently, for the purposes of determining whether modifications to Valero Transmission Company would be subject to PSD, Valero Transmission Company and Valero Gathering Company are considered to be one source.

On September 26, 1986, Mr. Ken Waid of Waid and Associates asked for clarification on how the distance between two facilities would affect the applicability of the PSD regulations' one source classification to such facilities. In the case of Valero Gathering Company and Valero Transmission Company, the distance between them does not affect the applicability of the PSD regulations' one source classification to such facilities since they are on contiguous properties. The gathering and transmission plants are one source for the reasons stated above. For cases where sources are not located on contiguous or adjacent properties, EPA cannot say precisely how far apart the activities must be in order to be treated separately. EPA can only answer that question through case-by-case determinations See 45 FR 52695 (August 7, 1980).

If you have any questions, please call Mr. Stanley M. Spruiell of my staff at (214) 767-9875.

Sincerely yours,

(s) JACK S. DIVITA

for
William B. Hathaway
Director
Air, Pesticides and Toxics Division (6T)

cc: Mr. Lawrence Pewitt, P.E., Director
Permits Division
Texas Air Control Board

bcc: Ascenzi (6T-EN)
Diggs (6T-AN)
Rasnic (EN-341)

EXHIBIT 14

Memo from Robert G. Kellam, OAQPS Acting Director, Information Transfer and Program Integration to Richard R. Long, Region VIII Director, Air Program
(August 27, 1996)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

AUG 27 1996

MEMORANDUM

SUBJECT: Analysis of the Applicability of Prevention of Significant Deterioration (PSD) to the Anheuser-Busch, Incorporated Brewery and Nutri-Turf, Incorporated Landfarm at Fort Collins, Colorado

FROM: Robert G. Kellam, Acting Director
Information Transfer & Program Integration Division, OAQPS (MD-12)

TO: Richard R. Long, Director
Air Program, Region VIII (8P2-A)

This is in response to your April 3, 1996 letter requesting PSD single stationary source determination for Anheuser-Busch's Fort Collins, Colorado brewery and Nutri-Turf landfarm. The Environmental Protection Agency (EPA) Headquarters considered the applicability of the PSD rules at 40 CFR 52.21 to the Anheuser-Busch, Inc. (Anheuser-Busch) brewery and the Nutri-Turf, Inc. (Nutri-Turf) landfarm in Fort Collins, Colorado.

PSD Applicability

The EPA Headquarters concurs with Region VIII's conclusion that the brewery and landfarm. are considered a single stationary source for PSD applicability purposes. Specifically, we conclude that the brewery and landfarm are commonly owned by AnheuserBusch, the brewery and landfarm are on contiguous or adjacent properties, and the landfarm. is a support facility for the brewery. In fact, the landfarm, which disposes of the brewery's waste water, is part of the brewery. The background information and details of the EPA's analysis follow.

Background

Anheuser-Busch received a PSD permit from EPA Region VIII on March 15, 1984 to construct a new brewery at Fort Collins, Colorado. The brewery was determined to be a major stationary source with potential emissions that exceeded significant emissions rates for nitrogen oxides, sulfur dioxide, and particulates. Potential volatile organic compound (VOC) emissions from the brewery were reported by Anheuser-Busch to be less than the PSD significant emissions rate of 40 tons per year. Anheuser-Busch did not report any air emissions from its Nutri-Turf landfarm in its original PSD application.

The brewery and landfarm are about 6 miles apart and are physically connected by a pipeline. Anheuser-Busch owns the brewery and landfarm. The landfarm was purchased and modified by Anheuser-Busch during the time the brewery was under construction for disposing of waste water from the brewery. The brewery waste water stream, containing hydrocarbons, is piped to the landfarm and disposed of by land application. The subsequent VOC emissions at the landfarm are a direct result of brewery operations. Land application of the waste water stream from the brewery at the landfarm began concurrently with-brewery production in 1988.

In 1986, the Colorado Department of Health (CDH) became the PSD permitting authority in Colorado, replacing EPA. In July 1993 the CDH issued a notice of violation to Anheuser-Busch for constructing VOC emitting units without valid permits at its Fort Collins brewery. Since the issuance of the PSD permit, the EPA and CDH determined that Anheuser-Busch did not include all of its potential VOC emissions at the brewery in its original PSD application. The VOC emissions from the brewery, excluding emissions from the landfarm, exceed the 40 tons per year significant emissions threshold for PSD applicability. An accurate calculation of potential VOC emissions from the landfarm has not yet been completed.

In response to an August 19, 1993 request from CDH, the EPA Region VIII determined in an October 23, 1993 letter that the brewery and landfarm are considered a single stationary source for PSD applicability. In January 31, 1995.and July 6, 1995 letters to CDH, Anheuser-Busch presented its position that the brewery and landfarm are two separate sources for PSD applicability purposes. After reviewing the positions presented by Anheuser-Busch, EPA Region VIII clarified and reaffirmed its previous single source determination in a letter to CDH dated September 20, 1995. Since EPA was the PSD permitting authority at the time the brewery was permitted, EPA is the responsible Agency for enforcement of any PSD violations at the brewery and landfarm based on the current-plant configurations.

PSD Definition of Source

The PSD requirements apply to the construction of major stationary sources and major modifications at major stationary particulates. Potential volatile organic compound (VOC) emissions from the brewery were reported by Anheuser-Busch to be less than the PSD significant emissions rate of 40 tons per year. Anheuser-Busch did not report any air emissions from its Nutri-Turf landfarm in its original PSD application.

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PSD Definition of Source

The PSD requirements apply to the construction of major stationary sources and major modifications at major stationary sources. See 40 CFR 52.21(i). The PSD regulations define stationary sources as any building, structure, facility, or installation that emits, or may emit any air pollutant subject to regulation under the Clean Air Act. See 40 CFR 52.21(b)(5). The regulations go on to define "building, structure, facility, or installation" as:

> all of the pollutant emitting activities that belong to the same industrial grouping, are 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 will 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, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock number 4101-0066 and 003-005-00176-0, respectively) [40 CFR 52.21(b)(6)].

The regulations do not expressly address how to classify a source composed of more than one grouping of pollutant emitting activities. However, in the preamble to these regulations, EPA explained that 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 that convey, store, or otherwise assist in the production of the principal product or group of products produced or distributed, or services rendered. Where a unit is used to support two otherwise distinct sets of activities, the unit is to be included within the source that , most heavily relies on its support. See 45 FR 52676, 52695 (August 7, 1980).

The criteria for defining a stationary source under the PSD regulations as they apply to the Anheuser-Busch brewery and landfarm situation are discussed below.

Contiguous or Adjacent

A specific distance between pollutant emitting activities has never been established by EPA for determining when facilities should be considered separate or one source for PSD purposes. Whether facilities are contiguous or adjacent is determined on a case-by-case basis, based on the relationship between the facilities. The EPA considers the brewery and landfarm, to be contiguous or adjacent since the landfarm operation is an integral part of the brewery operations, i.e., land application at the landfarm is the means chosen by Anheuser-Busch to dispose of the ethanol contaminated process water from the brewery operations. Without a means of waste water disposal the brewery cannot operate. The additional fact that a pipeline physically connects the brewery and landfarm strengthens the conclusion that the brewery operation is dependent on landfarm operations. For this case, the distance between the brewery and landfarm does not support a PSD determination that the brewery proper and the landfarm constitute separate sources for PSD purposes.

SIC Code

As noted, EPA's contemporaneous interpretation of the PSD regulations is that each source is to be classified according to its primary activity that is determined by its principal product or group of products. Thus, one source classification encompasses both primary and support facilities, even when it includes units with a different two-digit SIC code. Without an acceptable means of waste water disposal the brewery cannot produce beer. Land application at the landfarm is the waste water disposal means chosen by Anheuser-Busch for the brewery. Upon further review of the October 23, 1993, letter from Region VIII to CDH, the EPA believes that the landfarm is a support facility to the brewery since landfarm operations assist in the primary activity of the brewery. Even if the landfarm has a separate two-digit SIC code from the brewery, the landfarm is still a support facility for the brewery and considered part of the brewery. In other words, support activities are aggregated with their associated primary activity regardless of dissimilar SIC codes.

Common Control

Both the brewery and landfarm are under common control since they (as well as the pipeline connecting them) are owned by Anheuser-Busch. The landfarm was purchased and modified by Anheuser-Busch before the operation of the brewery.

This analysis has been reviewed by EPA's Office of Enforcement and Compliance Assurance and EPA's Office of General Counsel. If you have any questions please contact Mike Sewell of the Integrated Implementation Group at (919) 541-0873.

I appreciate this opportunity to be of service and trust this information will be helpful to you.

EXHIBIT 15

Letter from Joan Cabreza, Region X Permits Team Leader, Office of Air Quality to Andy Ginsberg, Manager, Program Operations Section, Air Quality Division, Oregon Department of Environmental Quality (August 7, 1997)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, Washington 98101

August 7, 1997

Reply To
Attn Of: OAQ-107

Andy Ginsberg, Manager
Program Operations Section
Air Quality Division
Oregon Department of Environmental Quality
811 SW Sixth Avenue
Portland, Oregon 97204-1390

Dear Mr. Ginsberg:

EPA has reviewed the additional information that you provided regarding the Title V permitting issue for the ESCO Corporation plants in Portland, Oregon. Nothing in the additional information changes EPA's position that the Main Plant and Plant 3 must be considered to be one major stationary source for purposes of major source permitting under the Federal Clean Air Act and the EPA-approved Oregon rules. In fact, as discussed in more detail below, the additional information provides a more clear basis for the determination that the two plants constitute a single major stationary source.

The definition of "major stationary source" requires a tripartite test for determining the geographic extent of a single stationary source. Specifically, a major stationary source is defined as all of the pollutant emitting activities that are (1) located on one or more contiguous or adjacent properties; (2) are under common control of the same person (or persons under common control); and (3) belong to a single major industrial grouping or are supporting the major industrial group (as determined by the Major Group codes in the Standard Industrial Classification Manual). In the case of the ESCO Main Plant and Plant 3, there is no dispute that the two plants are under common control (ESCO) and have the same Major Group SIC code (Major Group 33 - Primary Metal Industries). The only question is whether the two plants are "located on contiguous or adjacent properties."

The term "contiguous" is defined as "1. touching; in contact. 2. in close proximity without actually touching; near." The term "adjacent" is defined as "1. near or close; next or contiguous." (The Random House Dictionary of the English Language, College Edition). Therefore, by using the phrase "contiguous or adjacent properties" the definition of major stationary source clearly requires that properties that are located near each other, but are not actually touching, be grouped together as one stationary source if they meet the other two criteria. EPA has issued guidance as to how "near" properties need to be in order to be required to group them as a single stationary source. The guiding principle behind this guidance is the common sense notion of a plant. That is, pollutant emitting activities that comprise or support the primary product or activity of a company or operation must be considered part of the same stationary source.

In the case of the ESCO Main Plant and Plant 3, the primary product of both plants are coated (painted) metal castings. Essentially all of the castings produced by the foundries at both the Main Plant and Plant 3 are coated at the coating facility located at the Main Plant. Furthermore, all final production, packaging, shipping, etc. of the finished product is done at the Main Plant. Therefore, the Main Plant and Plant 3 together function in a manner which meets the common sense notion of a plant. While the Plant 3 foundry may function independently of the foundry facility at the Main Plant, that fact alone does not provide a basis for a finding that it is a separate stationary source in light of the dependent nature of Plant 3 on facilities located at the Main Plant.

ESCO's attorneys argue that the use of a common support facility should not form the basis of a determination that the two plants are contiguous or adjacent. EPA disagrees for two reasons. First, as discussed above, Plant 3 is entirely dependent upon the facilities at the Main Plant for production of the company's finished product. Second, ESCO's attorneys assertion that the coating facility is covered by a separate SIC code is incorrect. ESCO's attorneys claim that the coating facility is covered by SIC code 3479 is contradicted by the language of the SIC Manual itself which states "Establishments that both manufacture and finish products are classified according to their products." (see description of code 3479 in the Manual). Therefore, the coating facility is not considered part of the Main Plant simply because it is a collocated support facility with a separate SIC code. Rather, it is considered part of the same industrial grouping as the foundry facility because the primary activity of the Plant is the manufacturing and finishing of cast metal products.

ESCO's attorneys claim that EPA has never indicated that two plants that share common facilities should be grouped together as one stationary source. EPA disagrees and can point to several instances where two plants were required to be grouped together as one stationary source when one plant produced an intermediate product and the finished product was produced at the other plant. ESCO's attorneys also point to EPA's guidance for addressing situations where a support facility supports two stationary sources as a basis for their argument that a support facility cannot be the basis for grouping the two plants as one stationary source. However, EPA's guidance addresses situations where the two sources are clearly separate stationary sources (due to ownership and/or SIC code) and the support facility needs to be assigned to one or the other sources. However, where two sources are on contiguous or adjacent properties, are under common ownership, and are within the same SIC code, there would be only one stationary source and there would be no need to assign the support facility to one source or the other. Finally, ESCO's attorneys also point to an Illinois court decision as a basis for their argument that use of a common support facility should not form the basis for grouping two plants together as one source. This decision involved a challenge of a permit issued by an Illinois permitting authority and was decided based on the provisions of the Illinois Clean Air Act. As such, it has no relevance to the Federal Clean Air Act or Oregon's statutes. Moreover, the Illinois case involved the issue of whether two facilities with different 2-digit SIC codes were required to be grouped together as a single stationary source. Since all of the facilities involved in the ESCO situation have the same 2-digit SIC code, the Illinois case is irrelevant.

EPA's position on this issue represents the opinions of Region 10 Office of Air Quality and Office of Regional Counsel, EPA's Office of Air Quality Planning and Standards, and EPA's Office of General Counsel. If you have any further questions on this issue, please contact either David Bray, Office of Air Quality, at (206) 553-4253, or Adan Schwartz, Office of Regional Counsel, at (206) 553-0015.

Sincerely,

Joan Cabreza
Permits Team Leader
Office of Air Quality

EXHIBIT 16

Letter from Steven C. Riva, Region II Chief, Permitting Section, Air Programs Branch to John T. Higgins, Director, Bureau of Application Review and Permitting, Division of Air Resources, New York State Department of Environmental Conservation
(October 11, 2000)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 2
290 Broadway
New York, NY 10007-1866

October 11, 2000

Mr. John T. Higgins, P.E., Director
Bureau of Application Review and Permitting
Division of Air Resources
New York State Department of
Environmental Conservation
50 Wolf Road
Albany, New York 12233

Re: St. Lawrence Cement's (SLC's) Proposed Greenport Project and its Relationship with its Existing Catskill Facility Located 6 Miles Apart for the Purpose of New Source Review (NSR)/Prevention of Significant Deterioration of Air Quality (PSD) Applicability

Dear Mr. Higgins:

This is in response to the New York State Department of Environmental Conservation's (NYSDEC's) request for guidance regarding St. Lawrence Cement's (SLC's) pending permit application for its Hudson Valley Operation. SLC has expressed to NYSDEC and the Region 2 Office of the U.S. Environmental Protection Agency (EPA) its position as to why SLC's Catskill and Greenport facilities should be treated as one single source.

EPA's definition of a source is based on the "common sense" notion of a plant. See 45 Fed. Reg. 52676, 52695 (August 7, 1980). EPA has reviewed the information and arguments presented by SLC and Young, Sommer, Ward, Ritzenberg, Wooley, Baker & Moore, LLC (representing Friends of Hudson), to assess whether SLC's Catskill and Greenport facilities meet the "common sense" notion of a plant. As you are aware, such determinations are made on a case-by-case basis, and in some situations can require a careful weighing of the specific facts at hand to reach a conclusion. We recognize that with respect to the Catskill and Greenport facilities, the question of whether these two facilities comprise one or two sources is a difficult one. However, based upon this review, EPA Region 2, in coordination with our HQ's Office of Air Quality Planning and Standards and Office of General Counsel, has concluded that the best decision, in this particular case, is that the Catskill and Greenport facilities should be treated as two separate sources. Our reasoning is explained below.

Background

St. Lawrence Cement (SLC) has manufactured cement in the Hudson Valley of New York for over 25 years. SLC's current operations in the Hudson Valley consists of two facilities located on separate sides of the Hudson River approximately 6 miles apart: the Greenport facility located in the towns of Greenport and Hudson, NY and the Catskill facility located in Catskill, NY. SLC has proposed to modify its current cement manufacturing operations by shutting down its existing clinker manufacturing activities at the Catskill facility which utilizes the wet process and constructing a new, "technologically-advanced" facility at the Greenport facility which utilizes the dry process. The proposed project at the Greenport facility would include the following: the construction of a new cement plant in Greenport; the rehabilitation and expansion of SLC's existing Hudson River dock in the City of Hudson; the construction of a conveyor system connecting the Greenport plant to the dock; and the construction of a number of storage and other structures at the Greenport facility. The proposed new plant would manufacture up to 2.6 million tons of clinker per year.

SLC plans to shut down its existing plant for manufacturing clinker at the Catskill facility. However, SLC intends to continue limited operations at the Catskill facility consisting of: cement grinding; packaging; storage and shipping. In addition, SLC will continue to operate its existing landfill at Catskill to dispose of cement kiln dust.

Discussion

Since the NYSDEC has a PSD-delegated program, the federal definitions under 40 CFR 52.21 apply. 40 CFR Part 52.21(b)(5) defines "stationary source" as:

> ...any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

Furthermore, 40 CFR Part 52.21(b)(6) defines "building, structure, facility or installation," in pertinent part, 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 "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement....

Common Control

Because both the Greenport and Catskill facilities are wholly-owned and managed by SLC, these two facilities are under common control.

Industrial Grouping

In its permit application, SLC states that the Greenport and Catskill facilities currently have the same standard industrial classification (SIC) code of 3241 (Hydraulic Cement) which means "establishments primarily engaged in manufacturing hydraulic cement, including portland, natural, masonry, and pozzolana cements." Although it appears that the Greenport and Catskill facilities belong to the same industrial grouping at this time, there is some question whether the Catskill facility will continue to be classified as SIC code of 3241 once SLC shuts down the clinker manufacturing operations at the site. However, even assuming that the two facilities fall within different SIC codes, the Catskill facility could well be viewed as a support facility for the Greenport facility. Regardless, the SIC code is not a determining factor in this case because of the adjacency discussion that follows below.

Contiguous/Adjacent Location

Over the years, EPA has issued guidance in a number of cases regarding the question of whether two facilities should be considered contiguous or adjacent. As SLC has noted, there is no bright line, numerical standard for determining how far apart activities may be and still be considered "contiguous" or "adjacent." As explained in the preamble to the August 7, 1980 PSD rules, such a decision must be made on a case-by-case basis. Moreover, in further explaining this factor, EPA has noted that whether or not two facilities are adjacent depends on the "common sense" notion of a source and the functional inter-relationship of the facilities and is not simply a matter of the physical distance between the two facilities. However, the physical distance between two facilities is obviously a factor to be considered in deciding whether the two are close enough to be considered one source in a given situation.

The vast majority of the past EPA single-source decisions have involved operations that are situated less than 6 miles apart. Thus, the distance separating SLC's operations is distinctly farther than the majority of the past EPA single-source decisions. Where EPA has made single-source decisions in situations involving facilities separated by 6 or more miles, these cases have tended to involve a clear physical connection via a pipeline or dedicated conveyance. For example:

1. American Soda Commercial Mine and processing plant - Distance: approximately 35-40 miles, connected by a 44-mile long pipeline. (See April 20, 1999 letter from Richard R. Long, EPA Region 8, to Mr. Dennis Myers, Colorado Department of Public Health and Environment.)

2. Great Salt Lake Minerals plant and a pump station - Distance: 21.5 miles, connected by a dedicated channel or "pipeline." (See August 8, 1997 letter from Richard R. Long, EPA Region 8, to Lynn R. Menlove, Utah Department of Environmental Quality.)

3. Anheuser-Busch brewery and the Nutri-Turf, Inc. landfarm - Distance: approximately 6 miles apart, connected by a pipeline. (See August 27, 1996 letter from Robert Kellam, EPA OAQPS, to Richard R. Long, EPA Region 8.)

In each of these cases, although the facilities were separated by a number of miles, the two operations were physically connected by a pipeline or dedicated conveyance. We believe that this physical connection in these cases was a salient factor, demonstrating an integral connectedness between the facilities that led EPA to conclude that the facilities operated as one source. In the case of SLC, the two facilities are located approximately 6 miles apart, there is no pipeline or dedicated conveyance between the two operations, and the two facilities are separated by the Hudson River.

In this particular case, EPA has weighed the information before it and concluded that the two facilities are not close enough to be considered one source under the circumstances for purposes of NSR/PSD. No one factor was determinative in reaching this conclusion. Rather, we took into account a number of factors specific to the case at hand. As noted above, the two SLC facilities are located a greater distance from one another than many of the facilities which EPA has considered to be adjacent or contiguous. Although EPA has found facilities located 6 or more miles apart to be one source in a limited number of cases based on the specific circumstances of those cases, the actual physical connection between the facilities in those cases tends to suggest a high degree of functional interrelationship. Although a physical connection such as a dedicated pipeline is absent here, EPA did consider whether there were additional factors showing a functional relationship between the two facilities such that the two could be considered close enough to operate as one source. Specifically, it appears that cement kiln dust from the Greenport facility will be disposed of at the waste disposal operation at the Catskill facility, and that SLC expects to operate the two facilities in such a way as to create some functional interrelationship between them. However, given the six miles and the Hudson River separating the two facilities, it is EPA's opinion that SLC's somewhat generalized explanation of a limited functional interrelationship between the two facilities does not outweigh the evidence that the two facilities do not meet the "common sense" notion of a single plant.

Conclusion

Based on the totality of the above factors, we have concluded that SLC's Catskill and Greenport facilities do not meet the "common sense" notion of a single source and that they should be treated as two separate facilities when NYSDEC conducts its NSR and PSD applicability determination, and Title V permitting. This letter is not a final agency action on the part of EPA. Rather, we hope that it will assist the state to properly carry out its applicability review of SLC's PSD permit application.

If you have any questions, please call me at (212) 637-4074 or Frank Jon, of my staff, at (212) 637-4085.

Sincerely yours,

/s/

Steven C. Riva, Chief
Permitting Section
Air Programs Branch

cc: Thomas S. West, Attorney
LeBoeuf, Lamb, Greene & MacRae, L.L.P.

Leon Sedefian, NYSDEC - Albany

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

DEC - 9 1999

Ref: 8P-AR

Lee Ann Elsom
Environmental Coordinator
Citation Oil & Gas Corporation
P.O. Box 690688
Houston, TX 77269-0688

Dear Ms. Elsom,

This letter is in response to your letter dated October 18, 1999 requesting clarification of the Title V applicability to the Walker Hollow Unit. The Walker Hollow Unit is an oil and gas production field located on the Uintah and Ouray Indian Reservation. It occupies an approximate 12 miles radius of land and consists of oil and gas wells, pumps, line heaters, dehydration equipment, combustion equipment, and tank batteries.

In the Code of Federal Regulations at 40 CFR 71.2 the definition of "major source" states, in part:

> "Major source means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping....."

We interpret this to mean that each tank battery with its associated emitting units (e.g. wells, pumps, line heaters, dehydration equipment, combustion equipment, tanks, etc...) comprises a "group of stationary sources" and would be considered a single source for purposes of determining Title V applicability.

With this interpretation in mind, the additional information you provided to us in your letter, further telephone conversations, and facsimiles received on November 8, 1999 and November 9, 1999, we have determined that Citation Oil & Gas Corporation has four sources (tank batteries with their associated emitting units) located within the exterior boundaries of the Uintah and Ouray Indian Reservation in Northeast Utah. The enclosure to this letter illustrates the sources with their associated emitting units.

In addition, we have completed our evaluation of the potential emissions described in the enclosure to your letter dated October 18, 1999 for each of the tank batteries at the Walker Hollow Unit (also in the enclosure). It is our determination that none of the tank batteries are major sources as defined under the Federal Operating Permit regulations (40 CFR 71). As

EXHIBIT 17

Letter from Richard R. Long, Region VIII Director, Air and Radiation Program to Lee Ann Elsom, Environmental Coordinator, Citation Oil and Gas Corporation (December 9, 1999) long as the total potential emissions from all the pollutant emitting units at each tank battery of any pollutant remains below 100 tons per year and any hazardous air pollutant remains below 10 tons per year individually or 25 tons per year in aggregate, these sources will be considered minor sources under the Federal Operating Permit regulations.

This determination is based on the 1996 and 1997 emissions information contained in your letter and more recent information provided in your facsimiles. We recommend that you verify the correct status of the sources located on the Walker Hollow Field by conducting testing of the potential emissions from representative equipment and keeping records of changes and modifications to insure that the sources continue to operate as minor sources under the Federal Operating Permit regulations.

We hope that this has clarified for you our understanding of the regulations as they pertain to Citation Oil & Gas Corporation's Walker Hollow Field. If you have any further questions, please feel free to contact Kathleen Paser of my Technical Assistance staff at 303-312-6526.

Sincerely,

Richard R. Long, Director
Air and Radiation Program

Enclosure
cc: Elaine Willie, Environmental Coordinator, Ute Indian Tribe
Ed Kurip, Director AQM, Ute Indian Tribe

Walker Hollow Sources and Emission Summary

his is an estimate of the potential emissions based on 1996 and 1997 data provided by the source. The emission factors used to calculate the potential emission were provided by Citation Oil and Gas Coorporation. t has been recommended that Citation verify the correct status of these sources by conducting testing of the potential emissions from this equipment and by keeping operational records to nsure that these sources operate as minor sources.

Sattelite Battery

Wells dedicated to this battery = 18 Well Identification => 15, 21, 25, 43, 45, 46, 47, 54, 63, 64, 66, 69, 72, 73, 74, 75, 76, 77

	Number of Units	PM-10 (tpy)	Nox (tpy)	CO (tpy)	VOC (tpy)	Sox (tpy)	Benzene	Ethyl Benzene	Hexane	Toluene	Xylenes
16100 gal Crude Oil Storage Tank	1	0	0	0	5	0	0.004	0.0065	0	0.012	0.0065
).1 mmBTU/hr Natural Gas External Combustion Dehydrator	1	0	0.02	0.01	0	0	0	0	0	0	0
101 hp Natural Gas Internal Combustion Compressor	1	0.16	2.93	2.63	1.07	0.02	0	0	0	0	0
Dehydration Still Vent	1	0	0	0	0.89	0	0	0	0	0	0
).5 mmBTU/hr Natural Gas External Combustion Line Heaters	2	0.0188	0.1625	0.03375	0.01	0.00125	0	0	0	0	0
).75 mmBTU/hr Natural Gas External Combustion Line Heaters	10	0.145	1.22	0.2568	0.0705	0.006818	0	0	0	0	0
1.0 mmBTU/hr natural Gas External Combustion Line Heaters	9	0.1737	1.467	0.306	0.0837	0.006003	0	0	0	0	0
42 hp Natural Gas Internal Combustion Pump Drivers	3	0.195	4.86	1.824	0.486	0.03	0	0	0	0	0
30 hp Natural Gas Internal Combustion Pump Drivers	14	1.3	32.48	12.17	3.23	0.14	0	0	0	0	0
75 hp Electric Pump Drivers	1	0	0	0	0	0	0	0	0	0	0
Totals		2.0	43.1	17.2	10.8	0.2	0.0	0.0	0.0	0.0	0.0

Walker Hollow Sources and Emission Summary

This is an estimate of the potential emissions based on 1996 and 1997 data provided by the source. The emission factors used to calculate the potential emission were provided by Citation Oil and Gas Coorporation.
It has been recommended that Citation verify the correct status of these sources by conducting testing of the potential emissions from this equipment and by keeping operational records to insure that these sources operate as minor sources.

Tank Battery 1

Wells dedicated to this battery = 14 Well Identification => 1, 2, 3, 11, 13, 14, 16, 28, 40, 49, 52, G-1, G-59, 41

	Number of Units	PM-10 (tpy)	Nox (tpy)	CO (tpy)	VOC (tpy)	Sox (tpy)	Benzene	Ethyl Benzene	Hexane	Toluene	Xylenes
101 hp Natural Gas Engine	2	0.32	5.86	5.26	2.14	0.04	0	0	0	0	0
42700 gal crude oil storage tank	2	0	0	0	12.54	0	0.01	0.016	0	0.031	0.016
1.5 mmBTU/hr Natural Gas External Combustion Boiler	1	0.03	0.24	0.05	0.01	0	0	0	0	0	0
0.1 mmBTU/hr Natural Gas External Combustion Dehydrator	2	0	0.04	0.02	0	0	0	0	0	0	0
Dehydration Still Vent	2	0	0	0	7.92	0	0	0	0	0	0
1.5 mmBTU/hr Natural Gas External Combustion Treater	1	0.03	0.24	0.05	0.01	0	0	0	0	0	0
1.5 mmBTU/hr Natural Gas External Combustion Free Water Knock-Out	1	0.03	0.24	0.05	0.01	0	0	0	0	0	0
0.5 mmBTU/hr Natural Gas External Combustion Line Heaters	6	0.05625	0.4875	0.10125	0.03	0.00375	0	0	0	0	0
0.75 mmBTU/hr Natural Gas External Combustion Line Heaters	14	0.203	1.708	0.35952	0.0987	0.009545	0	0	0	0	0
1.0 mmBTU/hr natural Gas External Combustion Line Heaters	0	0	0	0	0	0	0	0	0	0	0
30 hp Natural Gas Internal Combustion Pump Drivers	1	0.046	1.16	0.435	0.116	0.01	0	0	0	0	0
42 hp Natural Gas Internal Combustion Pump Drivers	1	0.065	1.62	0.608	0.162	0.01	0	0	0	0	0
60 hp Natural Gas Internal Combustion Pump Drivers	8	0.744	18.56	6.95	1.85	0.08	0	0	0	0	0
40 hp Electric Pump Drivers	1	0	0	0	0	0	0	0	0	0	0
60 hp Electric Pump Drivers	1	0	0	0	0	0	0	0	0	0	0
Totals		1.5	30.2	13.9	24.9	0.2	0.0	0.0	0.0	0.0	0.0

Walker Hollow Sources and Emission Summary

This is an estimate of the potential emissions based on 1996 and 1997 data provided by the source. The emission factors used to calculate the potential emission were provided by Citation Oil and Gas Coorporation. It has been recommended that Citation verify the correct status of these sources by conducting testing of the potential emissions from this equipment and by keeping operational records to insure that these sources operate as minor sources.

Tank Battery 2

Wells dedicated to this battery = 14 Well Identification => 5, 20, 23, 24, 29, 36, 39, 37, 33, 42, 55, 56, 62, 38

	Number of Units	PM-10 (tpy)	Nox (tpy)	CO (tpy)	VOC (tpy)	Sox (tpy)	Benzene	Ethyl Benzene	Hexane	Toluene	Xylenes
1.25 mmBTU/hr Natural Gas Heater	1	0.02	0.2	0.04	0.01	0	0	0	0	0	0
1.50 mmBTU/hr Natural Gas Heater	2	0.06	0.48	0.1	0.02	0	0	0	0	0	0
3.00 mmBTU/hr Natural Gas Heater	1	0.06	0.49	0.1	0.03	0	0	0	0	0	0
42700 Crude oil tank	3	0	0	0	28.23	0	0.021	0.036	0	0.069	0.036
0.5 mmBTU/hr Natural Gas External Combustion Line Heaters	1	0.009375	0.08125	0.016875	0.005	0.000625	0	0	0	0	0
0.75 mmBTU/hr Natural Gas External Combustion Line Heaters	20	0.29	2.44	0.5136	0.141	0.0136	0	0	0	0	0
1.0 mmBTU/hr natural Gas External Combustion Line Heaters	2	0.0386	0.326	0.068	0.0186	0.001334	0	0	0	0	0
42 hp Natural Gas Internal Combustion Pump Drivers	2	0.13	3.24	1.22	0.324	0.02	0	0	0	0	0
60 hp Natural Gas Internal Combustion Pump Drivers	12	1.12	27.84	10.43	2.77	0.12	0	0	0	0	0
Totals		1.7	35.1	12.5	31.5	0.2	0.0	0.0	0.0	0.1	0.0

Walker Hollow Sources and Emission Summary

This is an estimate of the potential emissions based on 1996 and 1997 data provided by the source. The emission factors used to calculate the potential emission were provided by Citation Oil and Gas Coorporation. t has been recommended that Citation verify the correct status of these sources by conducting testing of the potential emissions from this equipment and by keeping operational records to nsure that these sources operate as minor sources.

Tank Battery 3

Wells dedicated to this battery = 0 Well Identification => Receives crude from other batteries

	Number of Units	PM-10 (tpy)	Nox (tpy)	CO (tpy)	VOC (tpy)	Sox (tpy)	Benzene	Ethyl Benzene	Hexane	Toluene	Xylenes
205500 gal crude oil storage tanks	2	0	0	0	62	0	0.048	0.078	0	0.151	0.08
1.5 mmBTU/hr Natural Gas External Combustion Boiler	1	0.03	0.24	0.05	0.01	0	0	0	0	0	0
0.5 mmBTU/hr Natural Gas External Combustion Line Heaters	5	0.046875	0.40625	0.084375	0.025	0.003125	0	0	0	0	0
0.75 mmBTU/hr Natural Gas External Combustion Line Heaters	1	0.0145	0.122	0.02568	0.00705	0.000682	0	0	0	0	0
1.0 mmBTU/hr natural Gas External Combustion Line Heaters	1	0.0193	0.163	0.034	0.0093	0.000687	0	0	0	0	0
Totals		0.1	0.9	0.2	62.1	0.0	0.0	0.1	0.0	0.2	0.1

EXHIBIT 18

Letter from Callie A. Videtich, Region VIII Leader, Air Technical Assistance Unit, to Roland Hea, Unit Leader, Construction Permit Program, Air Pollution Control Division, Department of Public Health and Environment (October 18, 2004)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18^{TH} STREET - SUITE 300
DENVER, CO 80202-2466
Phone 800-227-8917
http://www.epa.gov/region08

OCT 18 2004

Ref: 8P-AR

Roland Hea, Unit Leader
Construction Permit Unit
Stationary Sources Program
Air Pollution Control Division
Department of Public Health
and Environment
4300 Cherry Creek Drive South
Denver, CO 80222-1530

RE: EPA Comments on Draft Construction Permit #04GA0755 for Williams Production RMT Co.–Rifle Station

Dear Roland,

Thank you for the opportunity to review the draft construction permit for Williams Production RMT Co. (Williams), permit number 04GA0755 for their Rifle Station. EPA is submitting the following comments on the draft permit out for public comment in order to establish synthetic minor limits for this facility. We hope the enclosed comments will improve the permit and we look forward to working with you to resolve any issues before the final permit is issued. If you have any questions, please contact me at 303-312-6434 or Hans Buenning of my staff at 303-312-6438.

Sincerely,

Callie A. Videtich, Leader
Air Technical Assistance Unit

Enclosure

Enclosure

Comments on Colorado Draft Construction Permit #04GA0755
for
Williams – Rifle Station

Single Stationary Source Question for the Reconfigured Plant

The public comment notice describes the project that Williams has applied to have permitted as a synthetic minor source for purposes of the Title V program. Based on the information provided in the public notice, this facility (formerly known as Rifle Compressor Station) historically had natural gas compression capacity, but has since removed all of the compressors. The proposed permit is for a natural gas dehydration facility consisting of one natural gas sweetening unit, two natural gas triethylene glycol dehydration systems, one condensate tank, one condensate load out, and two natural gas fired heaters. This permit action proposes to limit the potential to emit from these units to 38.8 tons per year of volatile organic compounds, eight tons per year of a single hazardous air pollutant (HAP), and twenty tons per year of total HAPs.

In light of the equipment reconfiguration involved in this construction permit, we are concerned that this facility may be operating in conjunction with another natural gas facility or facilities as a single stationary source under the definitions found in Colorado Air Quality Control Commission's Regulation No. 3 for the New Source Review (NSR) and Title V programs. While the relevant facts necessary to make a final determination are not presently available to our office (and may not be presently available to your office), we believe that a natural gas facility operating without any compression capacity is likely supported by or supporting activities at a nearby natural gas facility or facilities with pollution emitting activities. As such, an analysis of how natural gas is transported to and from the Rifle Station should be conducted. The role the Rifle Station plays in the final product of any natural gas facility or facilities providing this compression should be established. Once this information is obtained, a factual and legal analysis should be conducted to determine if the Rifle Station is operating independently, or whether it should be considered a single stationary source with other pollutant emitting activities.

Under the circumstances of this permitting action, we recommend that the Division completely analyze whether the Rifle Station is truly operating independently as a single stationary source before establishing synthetic minor limits for the Title V program. We acknowledge that the definitions found in 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants) and 40 CFR Part 70 (State Operating Permit Programs) pertaining to oil and gas facilities precludes the level of detail in the analysis described above for defining a stationary source for HAPs that would be required for criteria pollutants under the NSR and Title V programs.