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DATE	Dec. 30 2011
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December 30, 2011

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Mike Monasmith
Project Manager
Systems Assessment & Facility Siting Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Subject: Supplemental Data Response, Set 1A
Hidden Hills Solar Electric Generating System (11-AFC-2)

Dear Mr. Monasmith:

On behalf of Hidden Hills Solar I, LLC; and Hidden Hills Solar II, LLC, please find attached electronic copies of Supplemental Data Response, Set 1A, which responds to questions raised at the workshops held in November and December 2011, information requested directly by staff (phone or email requests), or additional information that has become known since the AFC was filed. Due to the holidays, hard copies will be sent out on Tuesday, January 3, 2012.

Please call me if you have any questions.

Sincerely,

CH2M HILL

John L. Carrier, J.D.
Program Manager

Encl.

c: POS List
Project file

Supplemental Data Response, Set 1A

Hidden Hills

Solar Electric Generating System

(11-AFC-2)

Application for Certification

Hidden Hills Solar I, LLC; and Hidden Hills Solar II, LLC

December 29, 2011

With Technical Assistance from

CH2MHILL®

IS061411043744SAC

Hidden Hills Solar Electric Generating System (HHSEGS)

(11-AFC-2)

Supplemental Data Response, Set 1A
(Responses to Air Quality, Biological Resources, Cultural Resources and Water Resources)

Submitted to the

California Energy Commission

Submitted by

Hidden Hills Solar I, LLC; and
Hidden Hills Solar II, LLC

December 30, 2012

With Assistance from

CH2MHILL
2485 Natomas Park Drive
Suite 600
Sacramento, CA 95833

Contents

Attachments

Introduction

Attached are supplemental responses (Set 1) by Hidden Hills Solar I, LLC, and Hidden Hills Solar II, LLC (collectively, "Applicant") to the California Energy Commission (CEC) Staff's data requests for the Hidden Hills Solar Electric Generating System (HHSEGS) project (11-AFC-2). These materials are in response to questions raised at the workshops held in November and December 2011, information requested directly by staff (phone or email requests), or additional information that has become known since the AFC was filed.

The responses are grouped by individual discipline or topic area. Within each discipline area, the responses are numbered for tracking and reference convenience. New graphics or tables are numbered in reference to the Supplemental Data Request number. For example, if a table were used in response to Data Request AQ-1, it would be numbered Table AQ1-1. The first figure used in response to Data Request AQ-1 would be Figure AQ1-1, and so on. AFC figures or tables that have been revised have "R1" following the original number, indicating revision 1. Attachments are similarly numbered. All figures and attachments are at the end of this document.

Air Quality (AQ-1, AQ-6)

DATA REQUEST

AQ-1. Please discuss whether emissions from the mirror washing machines must be included as part of the stationary source for determining PSD applicability.

Response: Emissions from motor vehicle engines, including on-road and non-road vehicle engines, are specifically excluded from the definition of "stationary source" under the federal PSD regulations applicable in Inyo County. PSD applicability is set forth in 40 CFR §52.21(a)(2), "Applicability procedures," as follows:

> (i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

"Stationary source" is defined in the Clean Air Act in Title III, General Provisions, Section 302, Definitions, as follows:

> (z) Stationary Source – The term "stationary source" means generally any source of an air pollutant ***except those emissions resulting directly from an internal combustion engine for transportation purposes or from a nonroad engine or nonroad vehicle*** as defined in section 216. [emphasis added]

In summary, PSD applies to stationary sources, and emissions directly resulting from vehicles are specifically excluded from the definition of a stationary source. Therefore, GHG and criteria pollutant emissions from the mirror washing vehicles are specifically excluded as part of the HHSEGS stationary source under federal PSD regulations, and are not included in determining PSD applicability.

This issue was addressed in the PSD permitting process for the Palmdale Hybrid Power Project. In the PSD permit application, the applicant stated:

> "The Project will require periodic vehicle travel over the unpaved portions of the solar field to perform routine maintenance including mirror washing, maintenance inspections and repairs of the piping network, herbicide application and dust suppressant application. Criteria pollutant emissions are expected from the combustion of fuels in the vehicles and fugitive PM, PM10 and PM2.5 emissions are expected from vehicle traffic on the unpaved areas in the solar fields. As the project is one of the 28 listed source categories, fugitive emissions are accumulated with stationary source emissions. ***However, consistent with EPA policy, mobile source***

> ***emissions (i.e., tailpipe emissions) are not included in the source inventory.***"[1] [emphasis added]

EPA's assessment of project emissions subject to PSD review for the Palmdale Hybrid Power Project was consistent with this interpretation. Table 4-1 of EPA's "Fact Sheet and Ambient Air Quality Impact Report," issued for the Palmdale Hybrid project in August 2011,2 includes "maintenance vehicle traffic generating fugitive dust" in the project equipment list. Table 6-2 of the Fact Sheet/AAQIR (Attachment AQ1-1, attachments are located at the end of this document) explicitly shows that only fugitive road dust emissions from the maintenance vehicles were considered to be PSD-regulated pollutants.

Because the HHSEGS project includes one of the 28 listed source categories with 100 ton per year PSD major source thresholds (fossil fuel-fired boilers totaling more than 250 million Btu/hr heat input), fugitive emissions are required to be included in calculating the facility's potential to emit. The Applicant did not include fugitive PM_{10} and $PM_{2.5}$ emissions from the mirror washing machines in AFC Table 5.1-29, "Comparison of Project Emissions with PSD Major Source Thresholds." A revised version of the table, which includes a separate column for fugitive road dust emissions from the mirror washing machines, is presented below as Table 5.1-29R; revisions are shown in *italics*. The addition of fugitive road dust emissions from mirror cleaning activities does not change the conclusion that HHSEGS project emissions are below PSD applicability thresholds.

TABLE 5.1-29R
Comparison of Project Emissions with PSD Major Source Thresholds

Pollutant	Maximum Annual Project Emissions (tpy)	*Annual Emissions from Mirror Cleaning Activities (tpy)**	*Total Annual Project Emissions (tpy)*	PSD Major Source Threshold (tpy)	Is Facility a Major Source?
NO_2	12.3	*n/a*	*12.3*	100	No
SO_2	1.8	*n/a*	*1.8*	100	No
CO	30.2	*n/a*	*30.2*	100	No
VOC	4.8	*n/a*	*4.8*	100	No
PM_{10}	4.4	*3.3*	*7.7*	100	No
$PM_{2.5}$	4.4	*0.33*	*4.7*	100	No
CO_2e	99,700	*n/a*	*99,700*	100,000	No

* Fugitive road dust emissions from mirror washing machine traffic on unpaved areas in the solar fields. See Appendix 5.1B, Table 5.1B-11.

[1] Application for PSD Permit for Palmdale Hybrid Power Project," AECOM Environment, March 2009. Available at http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2011-0560-0002.

[2] "Fact Sheet and Ambient Air Quality Impact Report For a Clean Air Act Prevention of Significant Deterioration Permit, Palmdale Hybrid Power Project, PSD Permit Number SE 09-01," August 2011. Available at http://www.regulations.gov/#!documentDetail;D=EPA-R09-OAR-2011-0560-0004.

DATA REQUEST

AQ-2. Please discuss whether thermal NOx would be formed at the surface of the solar receivers.

Response: Thermal NOx is formed by the high temperature reaction of nitrogen with oxygen. As discussed on page 3 the attached article (Attachment AQ2-1),[3] thermal NOx formation becomes significant above about 1300°C (2370 °F). The Applicant expects that surface temperatures of the SRSG panels will reach approximately 700°C (about 1300°F), well below the range where thermal NOx will form. Therefore, thermal NOx is not expected to form at the surface of the solar receivers.

BACKGROUND

The following data requests were received from the public and provided to the Applicant by CEC staff.

AQ-3. I had concerns regarding the use of upper atmospheric data obtained from Elko, NV as its distance is rather significant from the project site.

I recognize Sierra Research cited missing data reported at 15% from the Desert Rock station but I have run into a variety of other air quality modeling in similar projects that did use the Desert Rock data within their modeling parameters.

Why do you believe the exclusion of Desert Rock data was appropriate?

Response: As discussed at p. 5.1-54 of the AFC, the Desert Rock, Nevada, meteorological monitoring site was Applicant's first choice for upper air data. However, EPA guidance on the use of meteorological data for regulatory modeling clearly states, "Applicants in regulatory modeling analyses are allowed to substitute for up to 10 percent of the data; conversely, ***the meteorological data base must be 90 percent complete*** (before substitution) in order to be acceptable for use in regulatory dispersion modeling"[4] and

> "Data acquired from the National Climatic Data Center (NCDC) occasionally have periods of missing data. If the lengths of these periods are not excessive, reasonable values may be substituted without seriously degrading the modeling results. As with on-site data, ***a data set which is less than 90% complete should not be used for air quality modeling purposes***."[5] [emphasis added]

Because the Desert Rock upper air data for the most recent 5-year period (concurrent with the surface meteorological data set) did not meet the 90 percent completeness criterion, the Desert Rock data could not be used for the HHSEGS project and another representative source of upper air data was needed. As described in the air quality section of the AFC, the next closest upper air station is Miramar Naval Air Station. However, upper air in a coastal location such as Miramar was not considered to be representative of conditions in a desert location such as the project site. Therefore, the next closest station, located in a similar

3 "Nitrogen Oxides (NOx), Why and How They Are Controlled," Clean Air Technology Center, OAQPS, U.S.EPA, November 1999.
4 U.S. EPA, "Meteorological Monitoring Guidance for Regulatory Modeling Applications," EPA-454/R-99-005; February 2000.
5 U.S. EPA (Atkinson, Dennis and Russell F. Lee), "Procedures for Substituting Values for Missing NWS Meteorological Data for Use in Regulatory Air Quality Models," 7/07/92. Available at http://www.epa.gov/ttn/scram/surface/missdata.txt

desert location, was used. Although Elko is 335 miles from the project site, the upper air meteorological conditions there are expected to be consistent with those at the project site. Use of the Elko station is consistent with EPA guidance, which states:

> "Although proximity of the meteorological monitoring site is an important factor, representativeness is not simply a function of distance. In some instances, even though meteorological data are acquired at the location of the pollutant source, they may not correctly characterize the important atmospheric dispersion conditions; e.g., dispersion conditions affecting sources located on the coast are strongly affected by off-shore air/sea boundary conditions - data collected at the source would not always reflect these conditions…Representativeness is a function of the height of the measurement. For example, one can expect more site-to-site variability in measurements taken close to the surface compared to measurements taken aloft. As a consequence, upper-air measurements are generally representative of much larger spatial domains then are surface measurements."[6] [emphasis added]

AQ-4: According to the modeling parameters described on pp. 27 (pdf file), "Wind-blown fugitive dust emissions, sources at or near the ground that are at ambient temperature and have negligible vertical velocity, will be modeled as area sources with a release height of 0.5 meters." This equates to a modeling height of 1.64 feet.

Is this a "standard" height used to model air quality for fugitive dust emissions?

Can you please explain how, in laymen's terms, "wind-blown fugitive dust emissions" are limited to a release height of 0.5 meters and how that applies to total dust pollutants resulting from wind impacts on disturbed areas to total air quality within the project site?

The reason for this questioning is, in laymen terms, I have seen even a slight bit of surface disturbance causes a large dust trail and/or plume that can be seen across the entire valley.

Response: The release height is the distance above the ground at which a modeled source's emissions are assumed to be released. A release height of 0.5 meter is a standard release height that is generally used in modeling wind-blown fugitive dust emissions.

The release height is the location from which atmospheric dispersion is assumed to begin. The ambient air quality model simulates the dispersion of the fugitive dust emissions based on the wind speed and direction for each hour in the meteorological data set. The model calculates how the dust is carried by the wind to each receptor in the receptor field surrounding the location where the dust is emitted. The release height does not affect or limit in any way how much dust is emitted or how the dust is carried by the winds. (In other words, the release height does not limit how far the dust particulates will travel.) Under high-wind conditions, the model will predict that the fugitive dust emissions will produce dust plumes consistent with the observations described in the data request.

AQ-5: In Appendix 5.1G, Cumulative Impact Assessment (Air Quality), pp. 4 (pdf), it states that an additional solar project is "being proposed for construction approximately

[6] See footnote 4.

6 miles away" and that, "...even if the project construction schedule were to coincide with HHSEGS project construction, the localized construction impacts are unlikely to cause any cumulative impacts with HHSEGS."

Response: The basis for this conclusion is the observation that:

> "Construction impacts alone for all modeled pollutants are expected to be below the most stringent state and national standards. With the exception of the 24-hour and annual average PM10 standards, construction activities are not expected to cause an exceedance of state or federal ambient air quality standards… Maximum PM_{10} and $PM_{2.5}$ impacts occur on the project site fenceline, and concentrations decrease rapidly within a couple of hundred meters or less of the project site. PM_{10} and $PM_{2.5}$ impacts are extremely localized." [page 5.1F-7, Appendix 5.1F (Construction Impacts)]

Even at the locations of maximum impacts, at the project fenceline, construction impacts from the HHSEGS project are not expected to cause any ambient air quality standards to be exceeded with the exception of PM_{10}, for which the standards are already exceeded. Construction impacts are shown by the modeling analysis to be extremely localized, and modeled impacts are shown to decrease rapidly beyond the facility fenceline. Based on these and similar results for other construction projects, the Applicant expects that the ambient air quality impacts of construction of the additional solar project will also be very localized. Therefore, any construction emissions from HHSEGS probably could not be measured 6 miles away; conversely, it is unlikely that construction emissions from the other solar project could be measured at the HHSEGS site.

AQ-6: On pp. 14 (pdf), the modeling parameters excluded any project that failed to have an issue date prior to 1/1/10.

If so, can you provide specific points where was it discussed in the publicly available literature on the HHSEGS project?

Why is this date used to exclude cites in the area that had issue dates prior to 1/1/10 regarding their possible cumulative impacts?

Response: The cumulative impacts analysis is discussed in several public documents, including Appendix 5.1G to the AFC and the proposed ambient air quality modeling protocol that was submitted to the CEC staff in April 2011.

The modeling protocol (included as Appendix 5.1H to the AFC) stated, "To address CEC requirements, a cumulative air quality modeling impacts analysis of the project's typical operating mode will be performed in combination with other stationary source emissions sources within a six-mile radius that have received construction permits since January 1, 2010, or are in the permitting process." The January 1, 2010, date is used to differentiate between projects that are already in operation and those that have not yet been constructed or operated. It is assumed that any project that obtained its permit before January 1, 2010, was operational during at least part of 2010. The effect of emissions sources that are already in operation are represented in the monitored background data, which include data collected in 2010. The procedure used to evaluate localized cumulative impacts is to determine whether there are sources of emissions that are likely to have an impact in combination with the proposed project. On p. 5.1G-1 of Appendix 5.1G, the AFC explains, "Localized impacts are evaluated by looking at other local sources of pollutants

that are not included in the background air quality data to determine whether these sources in combination with HHSEGS would be expected to cause significant cumulative air quality impacts." [emphasis added] The impacts from sources that received their permits before January 1, 2010, are not ignored; those impacts are accounted for in the monitored background concentrations that are added to the modeled impacts of the project and sources that were not in operation during the period represented by the background ambient data.

Biological Resources (BR-1)

DATA REQUEST

BR-1. The Applicant has discussed it's preference in relocating desert tortoise found on the site across the state line into Nevada. Please explain the basis for this approach.

Response: To minimize potential impacts to desert tortoise, Applicant proposes to move the desert tortoise found on the project site the shortest distance possible, which is into Nevada, as the project is located adjacent to the California-Nevada border. Applicant's proposed approach to desert tortoise translocation at HHSEGS is discussed in further detail below.

BACKGROUND

The purpose of a desert translocation plan is to guide efforts to prevent the death of desert tortoises and allow the translocated or augmented population to become self-sustaining in the long-term. The purposes of a desert translocation plan are to:

1. Prevent the death of desert tortoises by moving them to suitable nearby habitat,
2. Minimize impacts on resident desert tortoises outside fenced areas,
3. Minimize stress, disturbance, and injuries to translocated tortoises, and
4. Assess the success of the translocation effort through monitoring.

The selection of suitable nearby habitat is critical to the survival of translocated desert tortoises. It has been demonstrated that a desert tortoise retains knowledge of its home territory and its features (Berry 1986). Desert tortoises also take intermittent long excursions of 0.9 to 4.5 miles beyond the customary area of activity and retain familiarity with the extended area (Berry 1984). When desert tortoises are relocated beyond their home ranges and become disoriented, they may flee in straight lines of travel over distances of 4 miles or more (Berry 1986). Additionally, translocated tortoises can disperse from translocation sites and disrupt the social structure of resident populations (Berry 1986). Translocations can provide a vector for disease and requires safeguards.

Many of these problems can be avoided or reduced if the translocation is within the home range or familiar areas. It is difficult to know the precise extent of the home range and the areas familiar to a particular tortoise. The size of a home range depends on the local resource base and is variable over time (Franks 2002; Duda et al. 1999). Home range size has been estimated by some to cover from 2 to 660 acres (Berry 1984) and by some to range from 10 to 100 acres (Averill-Murray 2002; Barrett 1990; Duda et al. 1999; Ernst et al. 1994; Field et al. 2007; Martin 1995; O'Connor et al. 1994). Nevertheless, some conclusions can be drawn about probabilities. For instance, a home range of 100 acres would have a radius of approximately 0.22 mile. Therefore, when a tortoise is found in uniform habitat within this distance of a project boundary, there is a 50 percent probability that the territory extends beyond the project boundary. Placing the tortoise outside the nearest fence increases the probability that it will be within its home range or an area known to it from longer excursions. Translocations within or near the home range reduce the probability of communicating disease organisms. As the distance of translocation increases, probability of death, undesired dispersals and social disruptions increases.

Hidden Hills SEGS Site

Because the quality of habitat on the project site is not uniform, the probability of placing translocated tortoises within their home territory (or familiar areas) is increased because habitat and non-habitat areas are more clearly defined. The two desert tortoises encountered on the project site were within the Mojave Desert Scrub vegetation community, near the transition to Shadscale Scrub vegetation (see Figure BR1-1), which is very poor tortoise habitat, or non-habitat. The proximity of the Shadscale Scrub vegetation community to the location where the tortoises were observed suggests that they were near the western extremes of their home ranges. This increases the probability that the home range of these individuals extends farther to the east, into Nevada, than to the west. The best option for translocation is to move the tortoises to the nearest suitable habitat managed by the Bureau of Land Management (BLM) that is offsite, because there is a higher probability that the relocation area would be in the tortoise's home range, or that the tortoise is familiar with the area. Placing the animals found onsite across the border on BLM land to the east would keep them in Mojave Desert Scrub vegetation. It would also result in a translocation distance of less than 0.5 mile (see Figure BR1-1), which would likely keep the animal in its home territory, minimizing stress to it. By comparison, the nearest available offsite Mojave Desert Scrub vegetation located in California, is northwest of the known tortoise locations at a distance of more than 1.5 miles. Considering the size of typical desert tortoise home ranges, this is certainly outside of their home range. In addition, the potential California translocation site to the north of the project is separated from the tortoise home ranges by low-quality habitat with increased amounts of saltbush (see Figure BR1-2, and photos 1a through 4c), which has the effect of being a barrier and makes it unlikely that the tortoises have made excursions to that area and are familiar with it.

In addition to being farther from the tortoises' home range, the available habitat northwest of the project site in California is of lower quality than that of the offsite habitat to the east of the project site in Nevada. The photographs of the nearest proposed translocation site on BLM-managed land in Nevada and the nearest translocation site in California clearly show the difference in habitat quality (see Figure BR1-2, and photos 1a through 15b). The nearest California translocation site consists of a restricted patch of low-quality vegetative habitat bounded by the Town of Pahrump and other human activity on the north and east, the project site on the south, and the Pahrump Dry Lake bed to the west with the foothills of the Nopah Range beyond it. The lakebed is popular among teenagers as an unsupervised informal off-road recreation and party area with lots of 4X4 and all-terrain vehicle use. In addition, a new public shooting range is proposed to be located south of Pahrump, along the California/Nevada border, about 2.5 miles north of the project site. The outlying public lands are also impacted on a continuing basis by illegal dumping. Alternate public land sites, located south of the project site in California, are interspersed with dirt roads and private lands and are adjacent to the community of Calvada Springs/Charleston View. These threats degrade the quality of the habitat. Thus, in California, the only remaining alternate translocation sites would be even farther away in other valleys to the west or south.

HHSEGS Desert Tortoise Translocation

The most favorable place for translocation, based on biology and proximity, is immediately east of the project site on BLM-managed land in Nevada. In addition to likely being within the home range and familiar areas of the desert tortoises found on the project site, it

connects to vast tracks of suitable habitat. The majority of this area is public land managed by the BLM(see Figure BR1-3). It is farther from developments on private lands that increase human access and activity. It is farther from outdoor recreation areas. It is not heavily impacted by illegal dumping. The only development east of the project site in Nevada is a highly structured and access-controlled training facility that does not use surrounding public lands. Even if tortoises were translocated to locations in the California portion of the Pahrump Valley, they would range across the state line, as they probably do now.

Furthermore, legal protections in Nevada afford a high level of conservation. Desert tortoises are currently listed as a Threatened species under the Endangered Species Act (50 CFR 17.11 and 17.12). The BLM manages the adjacent public lands in Nevada under the same federal laws and regulations as it does in California. Federal protections apply equally in Nevada and California. Additionally, Nevada protects desert tortoise as a Threatened species under Nevada State statutes (NRS 501.105, 501.110, 501.181;NAC 503.080) and as the state reptile (NRS 235.065).

Translocation of the tortoises known to occur on the project site to nearby Mojave Desert Scrub vegetation located east of the project will afford a greater probability of survival. It would minimize stress, injury, competition and social disruptions between translocated and resident tortoises. The habitat is higher quality and has fewer threats. Legal protections and management controls are comparable in both states. Placement in the lower quality California habitat would not be offset by greater regulatory protection.

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DATA REQUEST

BR-2. Staff is confused since three vegetation types were used in the Biological Resources section of the AFC and five vegetation types were used in the URS Wetland Delineation Report (AFC Appendix 5.2E). Please clarify.

Response: The difference in the number of vegetation types used in the AFC as compared to the Wetland Delineation Report is the result of the use of different vegetation characterization methods that are specific to each topic area.

The objective of the wetland delineation was to determine if waters of the U.S. were present onsite and describe those water features that may be subject to regulation by the U.S. Army Corps of Engineers (ACOE) under Section 404 of the federal Clean Water Act (URS 2011). Concurrent with the wetland delineation, vegetation communities were broadly described using the following references: *A Manual of California Vegetation* (Sawyer and Keeler-Wolf 1995); *Preliminary Descriptions of Terrestrial Natural Communities of California* (Holland 1986), and *Biotic Communities of Southwestern United States and Northwestern Mexico* (Brown 1994). Because the focus of the wetland delineation was to identify and describe waters of the U.S., detailed vegetation descriptions were not provided in the Wetland Delineation Report.

The objectives of the botanical surveys performed onsite included identifying, describing, and mapping the site vegetation. Vegetation characterization methods employed by the botanical team are described in Section 5.2.5.5.2 of the AFC. The principle references used in naming and classifying vegetation include *Terrestrial Vegetation of California* (Barbour et al., 2007) and *A Manual of California Vegetation* (Sawyer et al., 2009). The method of vegetation classification presented in Sawyer et al. (2009) represents the vegetation classification standards for large-scale vegetation maps recently adopted by the state. These state standards meet the National Vegetation Classification System standards followed by federal agencies (CDFG, 2011). *Preliminary Descriptions of the Terrestrial Natural Communities of California* (Holland, 1986) and *Mojave Desert Ecosystem Program: Central Mojave Vegetation Database* (Thomas et al., 2004) were also consulted.

Site-specific information on species composition and habitat characteristics was used to determine which vegetation types were present within the project area. Dominant and subdominant plant species identified within each plant community were noted in the field during the spring 2011 protocol-level surveys. Vegetation types within the HHSEGS boundary, the 250-foot survey buffer, and the 1-mile buffer were mapped in the field using aerial photographic base maps. Vegetation types identified during the surveys are described in Section 5.2.6.3 of the AFC. The location and extent of all plant communities identified during the surveys and mapped onsite is depicted in AFC Figure 5.2-3, which is also shown on Figures BR1-1 and BR1-2. Photographs of the two vegetation types identified onsite are also provided in AFC Figure 5.2-4 (5 of 6 and 6 of 6).

The dominant plant species included in the vegetation descriptions provided in the Wetland Delineation Report and the AFC were compared to determine if substantial differences in the characterization of site vegetation exist. Table BR2-1 lists the vegetation types identified

in the Wetland Delineation Report and those described in the AFC. (The various vegetation communities are numbered.) Based on the comparison of the vegetation types contained in both reports, there is no significant difference since they essentially support the same dominant plants. Because greater level of focus and detail on plant species is provided in the AFC, we suggest that the vegetation classification terminology contained in the AFC be used as the principal reference.

TABLE BR2-1
Vegetation Types Observed at HHSEGS

Wetland Delineation Report	Botanical Resources Surveys (Presented in the AFC)	Discussion
1. Mojave Creosote Bush Scrub and 2. Creosote-Bush-White-Bursage Scrub	**1. Mojave Desert Scrub**	
Dominant plant species: Creosote bush (*Larrea tridentata*), white bursage (*Ambrosia dumosa*), Nevada jointfir (*Ephedra nevadensis*), spiny hop-sage (*Grayia spinosa*), and cheesebush (*Hymenoclea salsola).*	Dominant plant species: creosote bush (*Larrea tridentata)* and burrobush (Ambrosia dumosa). Plant associates include four-wing saltbush (*Atriplex canescens*), and rabbit-thorn (*Lycium pallidum var. oligospermum*).	Plant species composition data is limited in the wetland report. However, based on a comparison of the dominant plant species listed in both reports, these vegetation types essentially support the same dominant plants
3. Desert Saltbush Scrub	**2. Shadscale Scrub**	
Dominant plant species: four-winged saltbush (*Atriplex canescens*) and shadscale (*Atriplex confertifolia*). No other details provided	The dominant shrub is shadscale (*Atriplex canescens*). Associated shrubs include: winterfat (*Kraschenninikovia lanata*), desert allysum (*Lepidium fremontii*), Anderson's boxthorn (*Lycium andersonii*), rabbit-thorn, Emory's globemallow (*Sphaeralcea emoryi*), and Prince's plume (*Stanleya pinnata*).	Plant species composition data is limited in the wetland report. However, based on a comparison of the dominant plant species listed in both reports, these vegetation types essentially support the same dominant plants
4. Mojave Desert Wash Scrub, Mesquite Series	**Mesquite Thicket** (not included onsite)	
A woodland community dominated by an open and scattered canopy of honey mesquite trees (*Prosopis glandulosa*). At the project site, this series is extremely limited and only occurred in a few drainage areas. A few mesquite were found scattered around the project site in areas that appeared to pool during heavy rains, like ditches along roadsides. This vegetation community is rare at the project site.	Mesquite thickets dominated by honey mesquite (*Prosopis glandulosa*) with a shrub-like growth form occur on the sandy dunes within the 1-mile buffer, east of and adjacent to the HHSEGS site (AFC Figure 5.2-3). They are formed on large sandy dunes with unstable soils, and are not associated with washes and are not located on the project site.	There may be a few mesquite bushes onsite; however, a few bushes onsite do not create a mesquite thicket, a mesquite woodland community, or a Mojave desert wash scrub community. Mesquite woodland or wash scrub vegetation types are not present onsite. Mesquite thickets (with a shrub-like growth form) occur to the east on the sandy dunes within the 1-mile site buffer.

TABLE BR2-1
Vegetation Types Observed at HHSEGS

Wetland Delineation Report	Botanical Resources Surveys (Presented in the AFC)	Discussion
5. Disturbed/Developed Lands	**3. Disturbed (Ruderal) Lands**	The Wetland Delineation Report's description uses non-vegetated features (roads, and other landscape features) to define this category. The botanical survey relies upon plant species to describe vegetation. In the AFC, areas that contain higher concentrations of ruderal (weedy) plant species (and frequently ground disturbance or development) define the disturbed (ruderal) vegetation type. These approaches are not the same because the objective of the classification methods is different. Thus, the acreage calculations of disturbed/developed lands contained in the wetland report differs from that described in the AFC.

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Barbour, M.G., T. Keeler-Wolf, and A.A. Schoenherr. 2007. Terrestrial Vegetation of California. University of California Press, Berkeley.

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http://www.dfg.ca.gov/biogeodata/vegcamp/pdfs/VegMappingRpt_Central_Mojave_Vegetation_Database.pdf

URS. 2011. Approved Jurisdictional Determination Report. Hidden Hills Ranch Solar Project. Inyo County, California. Submitted to Mr. Bruce Henderson US Army Corps of Engineers. North Coast Branch, Regulatory Division, Ventura, CA. Submitted by: BrightSource Energy Inc. Report Prepared by: URS Corporation. Tucson, Arizona 85705. May 6.

Cultural Resources (CR-1)

DATA REQUEST

CR-1. The applicant provided additional cultural material in a confidential response provided as part of Data Adequacy Supplement B. Please incorporate that material into the Cultural Resources Technical Report (AFC Appendix 5.3B) and provide an electronic copy of the revised appendix to staff under a repeated request for confidentiality.

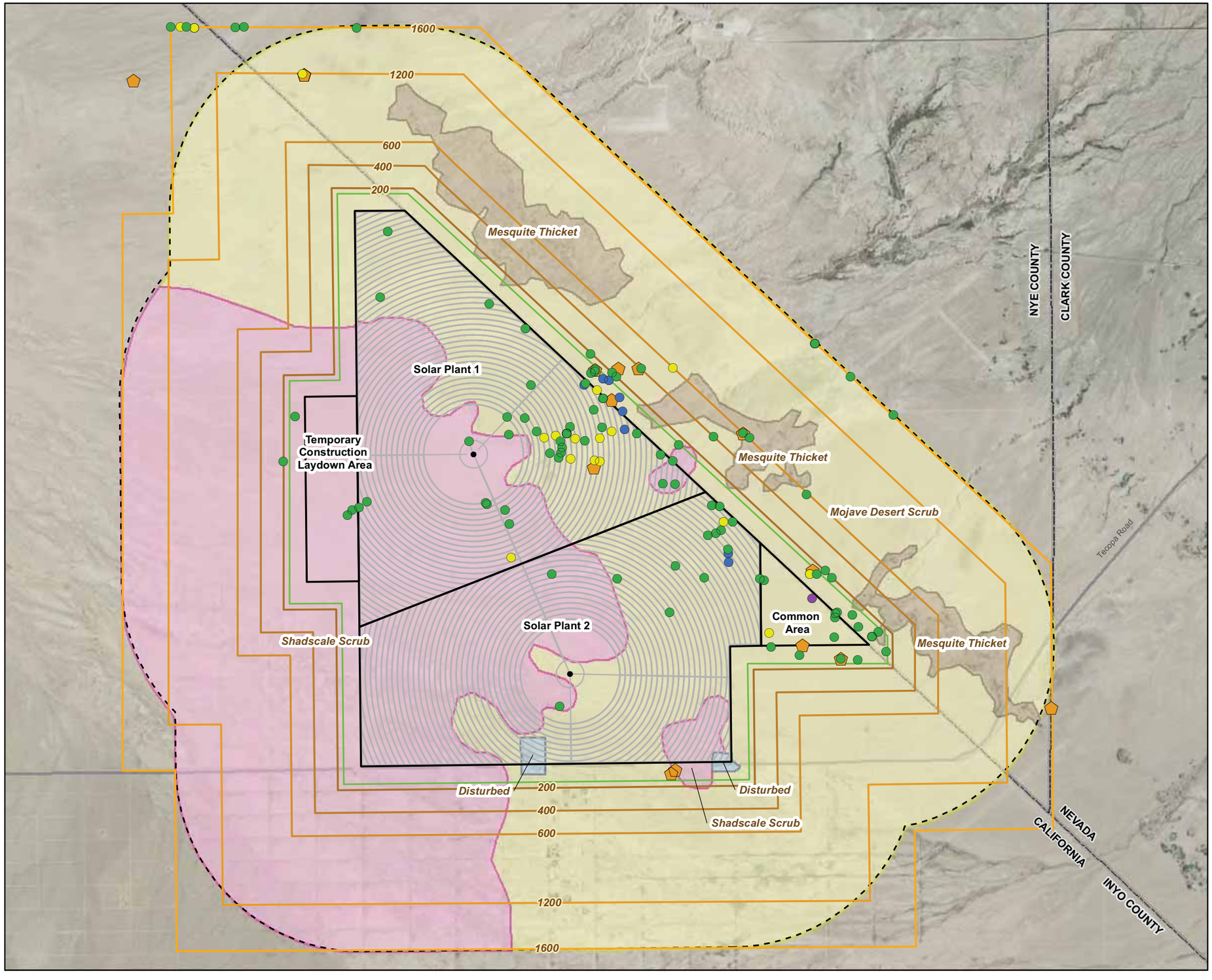
Response: Five CD-ROMs containing the revised material (Appendix 5.3B-R1) is being provided under a repeated request for designation.

Water Resources (WR-1)

WR-1. In reviewing AFC Table 5.15-4 it appears that some of the units may not be correct. Please verify.

Response: Table 5.15-4 has been corrected and is now Table 5.15-4R (indicating it has been revised). None of the results should have been presented as µg/L. Replacement pages for the AFC are attached.

FIGURES AND PHOTOS



LEGEND

- Solar Power Tower

Tortoise Data

- Live Tortoise
- Tortoise Burrow
- Tortoise Carcass
- Tortoise Scat
- Tortoise Tracks

Zone of Influence (ZOI) Survey Lines

- 200 meters
- 400 meters
- 600 meters
- 1200 meters
- 1600 meters

Project Site Data

- HHSEGS Boundary
- HHSEGS Buffer (1 mile)
- 150-meter Buffer of HHSEGS

Vegetation Coverage

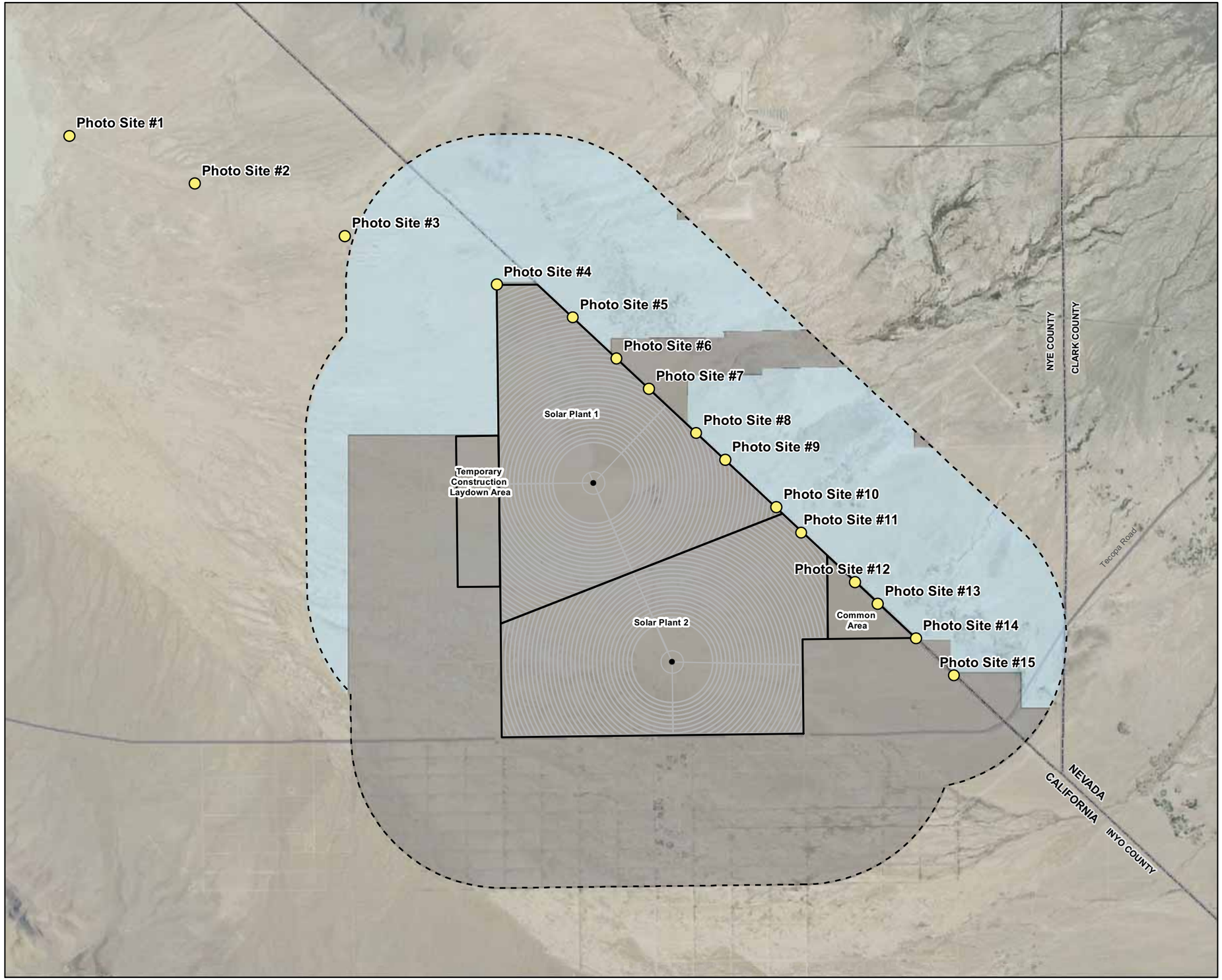
- Mesquite Thicket
- Disturbed (excluding roads)
- Shadescale Scrub
- Mohave Desert Scrub

Data Sources:
Tortoise Data: Sundance Biology, Inc.
Vegetation Data: GANDA Vegetation Survey, 2011

N

0 1,400 2,800
Feet

FIGURE BR1-1
Vegetation Designations and Tortoise Results
Hidden Hills Solar Electric Generating System



LEGEND

- Solar Power Tower
- Photo Site

Project Site Data

- HHSEGS Boundary
- HHSEGS Buffer (1 mile)

CA and NV Land Use (within 1 mile)

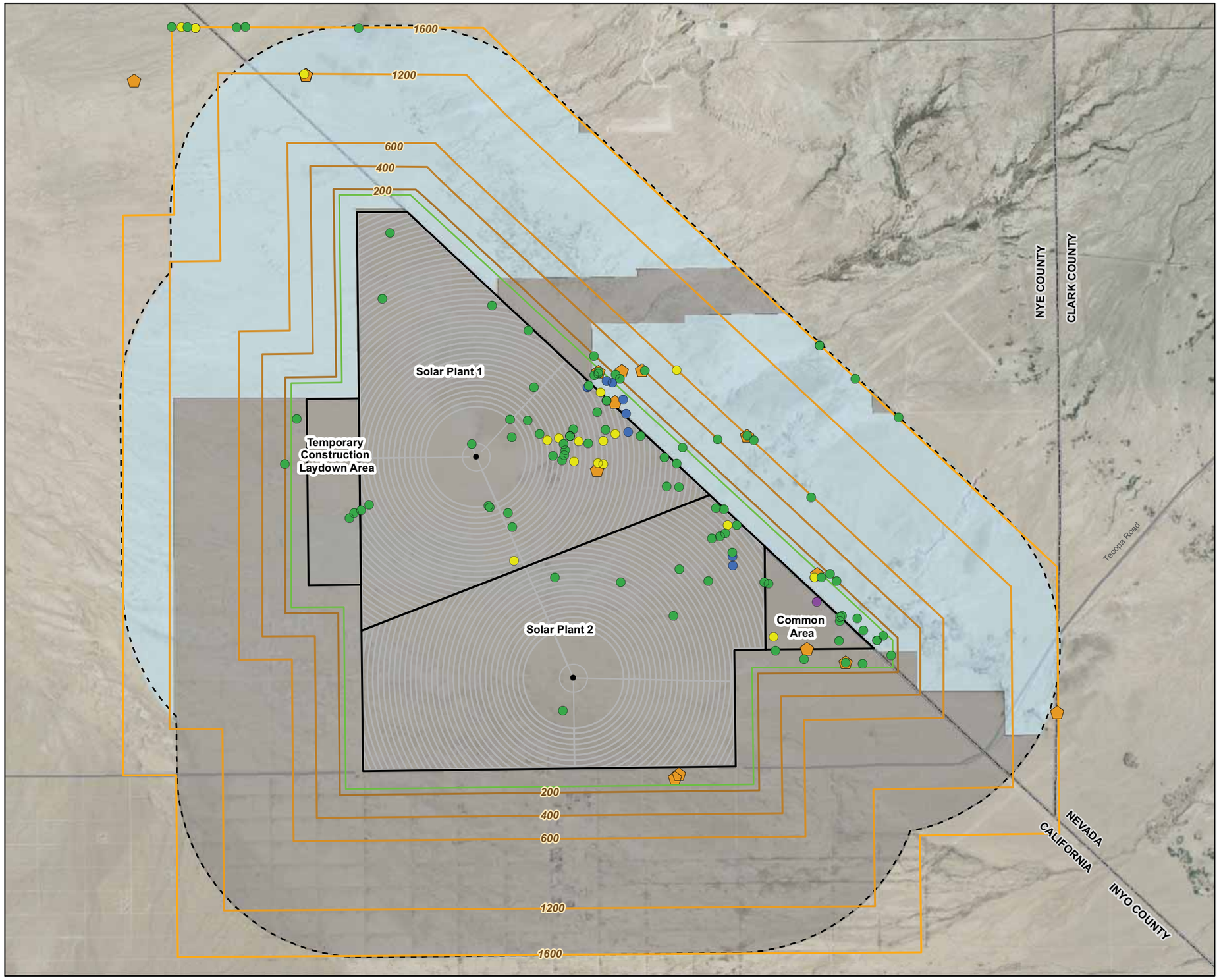
- Bureau of Land Management
- Private

N

0 1,750 3,500

Feet

FIGURE BR1-2
Photo Locations of Habitat
Hidden Hills Solar Electric Generating System



LEGEND

- Solar Power Tower

Tortoise Data

- Live Tortoise
- Tortoise Burrow
- Tortoise Carcass
- Tortoise Scat
- Tortoise Tracks

Zone of Influence (ZOI) Survey Lines

- 200 meters
- 400 meters
- 600 meters
- 1200 meters
- 1600 meters

Project Site Data

- HHSEGS Boundary
- HHSEGS Buffer (1 mile)
- 150-meter Buffer of HHSEGS

CA and NV Land Use (within 1 mile)

- Bureau of Land Management
- Private

Tortoise Data Source: Sundance Biology, Inc.

N

0 1,400 2,800
Feet

FIGURE BR1-3
Land Use Designations and Tortoise Results
Hidden Hills Solar Electric Generating System

1a. View looking north from Pahrump Dry Lake across the closest location for a BLM translocation site in California showing saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

1b. View looking east from Pahrump Dry Lake toward Nevada across the closest BLM translocation site in California showing saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

Photo Site 1 – Pahrump Dry Lake (593092 m E, 3987714 m N 11S)

1c. View looking south from Pahrump Dry Lake across the closest BLM translocation site in California showing saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

1d. View looking west from Pahrump Dry Lake across Pahrump Dry Lake.

Photo Site 1 – Pahrump Dry Lake (593092 m E, 3987714 m N 11S)

2a. View looking north from a location north of the Project site. View is across the closest location for a BLM translocation site in California showing saltbush vegetation, f ne soils in low-quality habitat for desert tortoise and the proximity of development in south Pahrump. Town of Pahrump is shown in the distance (zoomed photo).

2b. View looking east from a location north of the Project site across the closest location for a BLM translocation site in California showing saltbush vegetation, f ne soils in low-quality habitat for desert tortoise.

Photo Site 2 – 1 mile northwest of Photo Site 3 (594471 m E, 3987241 m N 11S)

2c. View looking south from a location north of the Project site across the closest location for a BLM translocation site in California showing saltbush vegetation, f ne soils in low-quality habitat for desert tortoise.

2d. View looking northwest from a location north of the Project site across the closest location for a BLM translocation site in California showing saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

Photo Site 2 – 1 mile northwest of Photo Site 3 (594471 m E, 3987241 m N 11S)

3a. View looking north from a location north of Project site toward Nevada across the closest location for a BLM translocation site in California showing the extent of the saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

3b. View looking east from a location north of Project site toward Nevada across the closest location for a BLM translocation site in California showing saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

Photo Site 3 – Sharp turn on Carpenter Street (595945 m E, 3986718 m N 11S)

3c. View looking south from a location north of Project site across the closest location for a BLM translocation site in California showing saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

3d. View looking west from a location north of Project site across the closest location for a BLM translocation site in California showing saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

Photo Site 3 – Sharp turn on Carpenter Street (595945 m E, 3986718 m N 11S)

4a. View looking north from the northwest corner of the Project site toward Nevada showing the saltbush vegetation and f ne soils in low-quality habitat for desert tortoise with impacts from continuing vehicular traff c.

4b. View looking northeast from the northwest corner of the Project site toward Nevada showing the saltbush vegetation and f ne soils in low-quality habitat for desert tortoise.

Photo Site 4 – Northwest corner HHSEGS project site

5a. View looking northeast from north end of the Project site at the state line. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

5b. View looking east from north end of the Project site at the state line. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 5 – North end of HHSEGS at Topaz Street and the state line

6a. View looking northeast from state line road along eastern perimeter of Solar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

6b. View looking east from state line road along eastern perimeter of Solar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 6 – At Avenue A and the state line

7a. View looking northeast from state line road along eastern perimeter of Solar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

7b. View looking east from state line road along eastern perimeter of Solar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 7 – At Silver Street and the state line

8a. View looking northeast from state line road along eastern perimeter of Solar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

8b. View looking east from state line road along eastern perimeter of Soar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 8 – At Avenue B and the state line

9a. View looking northeast from state line road along eastern perimeter of Solar Plant 1. View is toward Nevada showing transition to increasing saltbush vegetation from Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise in the distance.

9b. View looking east from state line road along eastern perimeter of Solar Plant 1. View is toward Nevada showing transition to increasing saltbush vegetation from Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise in the distance.

Photo Site 9 – At Zircon Street and the state line

10a. View looking northeast from state line road at southeast corner of Solar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

10b. View looking east from state line road at southeast corner of Solar Plant 1. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 10 – At Avenue C and the state line

11a. View looking northeast from state line road along edge of of Solar Plant 2. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

11b. View looking east from state line road along edge of of Solar Plant 2. View is looking east toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 11 – At Gold Street and the state line

12a. View looking northeast from state line road at north end of the Common Area. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

12b. View looking east from state line road at north end of the Common Area. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 12 – At Avenue D and the state line

13a. View looking northeast along state line road from middle of the Common Area. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

13b. View looking east along state line road from middle of the Common Area. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 13 – At unnamed dirt road and the state line, 1/2 mile southeast of Photo Site 12

14a. View looking northeast from state line road at southeast corner of the Common Area. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

14b. View looking east from state line road at southeast corner of the Common Area. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 14 – At southeast corner of the Common Area

15a. View looking northeast from state line road south of the Project site. View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

15b. View looking east from state line road south of the Project site View is toward Nevada showing Mohave Desert Scrub vegetation and alluvial soils and suitable habitat for desert tortoise.

Photo Site 15 – Along the state line, about 1/3 mile southeast of HHSEGS

ATTACHMENTS

Attachment AQ1-1
Table 6-2 from Palmdale Hybrid Fact Sheet/AAQIR

Table 6-2: Estimated Emissions of PSD-Regulated Pollutants by Emission Unit

	CO	NO_X	PM	PM_{10}	$PM_{2.5}$	GHG (a)	CO_2e (b)
Total Facility	**250.2 tpy**	**114.9 tpy**	**79.1 tpy**	**62.5 tpy**	**56.0**	**1,913,376**	**1,913,000**
CTG+HRSG (2)	248.0	113.7	47.8	47.8	47.8	1,908,074	1,908,000
Auxiliary Heater	0.74	0.22	0.15	0.15	0.15	2,340	2,000
Auxiliary Boiler	1.01	0.30	0.20	0.20	0.20	2,920	3,000
Emergency Diesel Engine	0.39	0.67	0.02	0.02	0.02	27.6	0
Emergency Diesel Firewater Pump	0.03	0.03	0.002	0.002	0.002	4.41	0
Cooling Tower	n/a	n/a	7.13	7.13	7.13	n/a	n/a
Circuit Breakers	n/a	n/a	n/a	n/a	n/a	9.56	0
Maintenance Vehicles (c)	n/a	n/a	23.80	7.16	0.72	n/a	n/a

Notes:

(a) Represents all GHG emissions on a mass basis.

(b) Represents the carbon dioxide equivalent (CO_2e) of all GHG emissions, rounded to the nearest 1,000 tons.

(c) This category represents fugitive road dust emissions (e.g., particulate matter emissions) that are expected from maintenance vehicle traffic on the unpaved areas in the solar fields.

Attachment AQ2-1
U.S. EPA Technical Bulletin: Nitrogen Oxides, Why and How They Are Controlled

United States Environmental Protection Agency
Air

Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

EPA 456/F-99-006R
November 1999

EPA

TECHNICAL BULLETIN

NITROGEN OXIDES (NOx), WHY AND HOW THEY ARE CONTROLLED

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C ENTER

EPA-456/F-99-006R
November 1999

Nitrogen Oxides (NOx), Why and How They Are Controlled

Prepared by

Clean Air Technology Center (MD-12)
Information Transfer and Program Integration Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

DISCLAIMER

This report has been reviewed by the Information Transfer and Program Integration Division of the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency and approved for publication. Approval does not signify that the contents of this report reflect the views and policies of the U.S. Environmental Protection Agency. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available form the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, Virginia 22161, telephone number (800) 553-6847.

CORRECTION NOTICE

This document, EPA-456/F-99-006**a**, corrects errors found in the original document, EPA-456/F-99-006. These corrections are:

Page 8, fourth paragraph: "Destruction or Recovery Efficiency" has been changed to "Destruction or Removal Efficiency;"

Page 10, Method 2. Reducing Residence Time: This section has been rewritten to correct for an ambiguity in the original text.

Page 20, Table 4. Added Selective Non-Catalytic Reduction (SNCR) to the table and added acronyms for other technologies.

Page 29, last paragraph: This paragraph has been rewritten to correct an error in stating the configuration of a typical cogeneration facility.

Page30, Internal Combustion Reciprocating Engines: A sentence has been added to the end of this section to refer the readers to Table 13 for more information;

Page 41, third through seventh paragraphs: These paragraphs were renumbered to correct for a numbering error (numbers 6 and 7 were used twice).

FORWARD

The **Clean Air Technology Center (CATC)** serves as a resource on all areas of emerging and existing air pollution prevention and control technologies, and provides public access to data and information on their use, effectiveness and cost. In addition, the CATC will provide technical support, including access to EPA's knowledge base, to government agencies and others, as resources allow, related to the technical and economic feasibility, operation and maintenance of these technologies.

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  - Source Specific Technology Applications
  - Air Pollution Regulatory Requirements

- **CATC PRODUCTS**

  download technical reports, cost information and software

Related Programs and Centers

- **CICA - U.S.-Mexico Border Information Center on Air Pollution /**
  Centro de Información sobre Contaminación de Aire Para la Frontera entre EE.UU. Y México
- **SBAP - Small Business Assistance Program**
- **International Technology Transfer Center for Global Greenhouse Gasses**

ACKNOWLEDGMENTS

This technical bulletin was made possible through the diligent and persistent efforts of Lyndon Cox, Senior Environmental Employee with the Clean Air Technology Center (CATC). Lyndon did an exceptional job identifying information sources, gathering relative data and putting this bulletin together. The CATC also appreciates the helpful and timely comments and cooperation of the following peer reviewers:

Jim Eddinger, Combustion Group, Emission Standards Division, Office of Air Quality Planning and Standards, Office of Air and Radiation, U.S. EPA.

Doug Grano, Ozone Policy and Strategies Group, Air Quality Strategies and Standards Division, Office of Air Quality Planning and Standards, Office of Air and Radiation, U.S. EPA.

William Vatavuk, Innovative Strategies and Economics Group, Air Quality Strategies and Standards Division, Office of Air Quality Planning and Standards, Office of Air and Radiation, U.S. EPA.

Ravi Strivastava, Air Pollution Technology Branch, Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, U.S. EPA.

In addition, the CATC thanks the individuals, companies and institutions who supplied information on nitrogen oxide abatement technology used to prepare this Technical Bulletin. Contributors are indicated in the REFERENCES section of this bulletin.

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FIGURES

TABLES

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Nitrogen Oxides (NOx), Why and How They Are Controlled

When we try to look only at one thing in Nature,
we find it connected to everything else.
John Muir

Nitrogen oxides (NOx) are a very interesting and important family of air polluting chemical compounds. This bulletin explains why NOx are important air pollutants and how NOx are formed and react in the atmosphere. This bulletin also discusses the principles on which all NOx control and pollution prevention technologies are based; available NOx technologies for various combustion sources; and performance and cost of NOx technologies..

WHY SHOULD WE CONTROL NOx?

NOx represent a family of seven compounds. Actually, EPA regulates only nitrogen dioxide (NO_2) as a surrogate for this family of compounds because it is the most prevalent form of NOx in the atmosphere that is generated by anthropogenic (human) activities. NO_2 is not only an important air pollutant by itself, but also reacts in the atmosphere to form ozone (O_3) and acid rain. It is important to note that the ozone that we want to minimize is tropospheric ozone; that is, ozone in the ambient air that we breathe. We are not talking about stratospheric ozone in the upper atmosphere that we cannot breathe. Stratospheric ozone protects us and the troposphere from ionizing radiation coming from the sun.

EPA has established National Ambient Air Quality Standards (NAAQS) for NO_2 and tropospheric ozone. The NAAQS define levels of air quality that are necessary, with a reasonable margin of safety, to protect public health (primary standard) and public welfare (secondary standard) from any known or anticipated adverse effects of pollution. The primary and secondary standard for NO_2 is 0.053 parts per million (ppm) (100 micrograms per cubic meter), annual arithmetic mean concentration.

Tropospheric ozone has been and continues to be a significant air pollution problem in the United States and is the primary constituent of smog. Large portions of the country do not meet the ozone NAAQS and thereby expose large segments of the population to unhealthy levels of ozone in the air. NO_2 reacts in the presence of air and ultraviolet light (UV) in sunlight to form ozone and nitric oxide (NO). The NO then reacts with free radicals in the atmosphere, which are also created by the UV acting on volatile organic compounds (VOC). The free radicals then recycle NO to NO_2. In this way, each molecule of NO can produce ozone multiple times.[40] This will continue until the VOC are reduced to short chains of carbon compounds that cease to be photo reactive (a reaction caused by light). A VOC molecule can usually do this about 5 times.

In addition to the NO_2 and Ozone NAAQS concerns, NOx and sulfur oxides (SOx) in the

atmosphere are captured by moisture to form acid rain. Acid rain, along with cloud and dry deposition, severely affects certain ecosystems and directly affects some segments of our economy. All of these facts indicate an obvious need to reduce NOx emissions. However, to successfully do so, we must understand the generation and control of the NOx family of air pollutants.

WHAT IS A NITROGEN OXIDE?

Diatomic molecular nitrogen (N_2) is a relatively inert gas that makes up about 80% of the air we breathe. However, the chemical element nitrogen (N), as a single atom, can be reactive and have ionization levels (referred to as valence states) from plus one to plus five. Thus nitrogen can form several different oxides. Using the Niels Bohr model of the atom, valence state relates to the number of electrons which are either deficient (positive valence) or surplus (negative valence) in the ion when compared with the neutral molecule. The family of NOx compounds and their properties are listed in Table 1.

Table 1. Nitrogen Oxides (NOx)

Formula	Name	Nitrogen Valence	Properties
N_2O	nitrous oxide	1	colorless gas water soluble
NO N_2O_2	nitric oxide dinitrogen dioxide	2	colorless gas slightly water soluble
N_2O_3	dinitrogen trioxide	3	black solid water soluble, decomposes in water
NO_2 N_2O_4	nitrogen dioxide dinitrogen tetroxide	4	red-brown gas very water soluble, decomposes in water
N_2O_5	dinitrogen pentoxide	5	white solid very water soluble, decomposes in water

Oxygen ions are always at valence minus 2. Depending upon the number of oxygen ions (always balanced by the valence state of nitrogen), NOx can react to either deplete or enhance ozone concentrations. The nitrogen ion in these oxides really does a dance in which it has (at different times) various numbers of oxygen ions as partners. Nitrogen changes its number of partners when it changes its ionization energy level. This happens whenever NOx: (1) is hit with a photon of ionizing radiation (UV or a shorter wavelength light); (2) is hit with enough photons that together transfer enough energy to change its ionization level; (3) is catalyzed; (4) is stimulated sufficiently by thermal (IR) energy; (5) reacts with a chemically oxidizing or reducing radical (an ionized fragment of a molecule); or (6) reacts with a chemically oxidizing or reducing

ion (an atom with unbalanced electrical charge).

When any of these oxides dissolve in water and decompose, they form nitric acid (HNO_3) or nitrous acid (HNO_2). Nitric acid forms nitrate salts when it is neutralized. Nitrous acid forms nitrite salts. Thus, NOx and its derivatives exist and react either as gases in the air, as acids in droplets of water, or as a salt. These gases, acid gases and salts together contribute to pollution effects that have been observed and attributed to acid rain.

Nitrous oxide (N_2O), NO, and NO_2 are the most abundant nitrogen oxides in the air. N_2O (also known as laughing gas) is produced abundantly by biogenic sources such as plants and yeasts. It is only mildly reactive, and is an analgesic (i.e., unlike an anaesthetic you still feel pain, but you feel so good that you just don't mind it). N_2O is an ozone depleting substance which reacts with O_3 in both the troposphere (i.e., below 10,000 feet above sea level) and in the stratosphere (50,000 - 150,000 feet). N_2O has a long half-life, estimated at from 100 to 150 years.

Oxidation of N_2O by O_3 can occur at any temperature and yields both molecular oxygen (O_2) and either NO or two NO molecules joined together as its dimer, dinitrogen dioxide (N_2O_2). The NO or N_2O_2 then oxidizes quickly (in about two hours) to NO_2. The NO_2 then creates an ozone molecule out of a molecule of oxygen (O_2) when it gets hit by a photon of ionizing radiation from sunlight. N_2O is also a "Greenhouse Gas" which, like carbon dioxide (CO_2), absorbs long wavelength infrared radiation to hold heat radiating from Earth, and thereby contributes to global warming.

Emissions of NOx from combustion are primarily in the form of NO. According to the Zeldovich equations, NO is generated to the limit of available oxygen (about 200,000 ppm) in air at temperatures above 1,300°C (2,370°F). At temperatures below 760°C (1,400°F), NO is either generated in much lower concentrations or not at all. Combustion NO is generated as a function of air to fuel ratio and is more pronounced when the mixture is on the fuel-lean side of the stoichiometric ratio[50] (the ratio of chemicals which enter into reaction). The Zeldovich equations are:

$$N_2 + O \rightarrow NO + N$$
$$N + O_2 \rightarrow NO + O$$
$$N + OH \rightarrow NO + H$$

Except for NO from soils, lightning and natural fires, NO is largely anthropogenic (i.e., generated by human activity). Biogenic sources are generally thought to account for less than 10% of total NO emissions. NO produces the same failure to absorb oxygen into the blood as carbon monoxide (CO). However, since NO is only slightly soluble in water, it poses no real threat except to infants and very sensitive individuals.

NO_2 is present in the atmosphere and in acid rain. It produces nitric acid (HNO_3) when dissolved in water. When NO_2 reacts with a photon to make O_2 become O_3, NO_2 becomes NO. This NO is then oxidized within hours to NO_2 by radicals from the photo reaction of VOC. Therefore, our

present ozone concentration is the product of both NOx and VOC pollution.

Dinitrogen trioxide (N_2O_3) and dinitrogen tetroxide (N_2O_4) exist in very small concentrations in flue gas. However, they exist in such low concentrations in the atmosphere that both their presence and their effect are often ignored. N_2O_4 is two NO_2 molecules joined together (another dimer) and reacts like NO_2; so, the presence of N_2O_4 may be masked by the more abundant NO_2.

Dinitrogen pentoxide (N_2O_5) is the most highly ionized form of nitrogen oxide. It is generated in air in a very small concentration, unless it is emitted from a process (such as a nitric acid production facility) that is specifically designed to generate it. N_2O_5 is highly reactive, and forms nitric acid (HNO_3) when it decomposes in water.

Some experts feel that NO_2 is a good surrogate for NOx because NO is rapidly converted to NO_2, and N_2O has such a long life because it is not highly reactive. Others feel that due to their role in forming ozone, both NO and NO_2 should be considered NOx. Still others feel that all nitrogen oxides (including N_2O) need to be regulated. NO and NO_2 are certainly the most plentiful forms of NOx and they are largely (but not exclusively) from anthropogenic sources. N_2O is largely biogenic, and as such is not subject to regulation. For environmental purposes, using the concentration of NO_2 as a surrogate for the concentration of NOx has seemed to suffice, for it is the precursor for ozone.

WHERE DOES NOx COME FROM?

Automobiles and other mobile sources contribute about half of the NOx that is emitted. Electric power plant boilers produce about 40% of the NOx emissions from stationary sources.[34] Additionally, substantial emissions are also added by such anthropogenic sources as industrial boilers, incinerators, gas turbines, reciprocating spark ignition and Diesel engines in stationary sources, iron and steel mills, cement manufacture, glass manufacture, petroleum refineries, and nitric acid manufacture. Biogenic or natural sources of nitrogen oxides include lightning, forest fires, grass fires, trees, bushes, grasses, and yeasts.[1] These various sources produce differing amounts of each oxide. The anthropogenic sources are approximately shown as:

Mobile Sources	Electric Power Plants	Everything Else
50%	20%	30%

This shows a graphic portrayal of the emissions of our two greatest sources of NOx. If we could reduce the NOx emissions from just these two leading categories, we might be able to live with the rest. However, don't expect either of these categories to become zero in the foreseeable future. We cannot expect the car, truck, bus, and airplane to disappear. The zero-emission car is still on the drawing board and not on the production line. Also, social customs will have to change before consumption of electricity can be reduced.

In all combustion there are three opportunities for NOx formation. They are:

1. Thermal NOx - The concentration of "thermal NOx" is controlled by the nitrogen and oxygen molar concentrations and the temperature of combustion. Combustion at temperatures well below 1,300°C (2,370°F) forms much smaller concentrations of thermal NOx.

2. Fuel NOx - Fuels that contain nitrogen (e.g., coal) create "fuel NOx" that results from oxidation of the already-ionized nitrogen contained in the fuel.

3. Prompt NOx - Prompt NOx is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions which exist, to some extent, in all combustion. This nitrogen then oxidizes along with the fuel and becomes NOx during combustion, just like fuel NOx. The abundance of prompt NOx is disputed by the various writers of articles and reports - probably because they each are either considering fuels intrinsically containing very large or very small amounts of nitrogen, or are considering burners that are intended to either have or not have fuel-rich regions in the flame.

HOW DOES NOx AFFECT THE ENVIRONMENT?

Because NOx are transparent to most wavelengths of light (although NO_2 has a brownish color and the rare N_2O_3 is black), they allow the vast majority of photons to pass through and, therefore, have a lifetime of at least several days. Because NO_2 is recycled from NO by the photo reaction of VOC to make more ozone, NO_2 seems to have an even longer lifetime and is capable of traveling considerable distances before creating ozone. Weather systems usually travel over the earth's surface and allow the atmospheric effects to move downwind for several hundred miles. This was noted in EPA reports more than twenty years ago. These reports found that each major city on the East coast has a plume of ozone that extends more than a hundred miles out to sea before concentrations drop to 100 parts per billion (ppb). Another report cited the same phenomenon for St. Louis. Therefore, this problem was not just on the sea coast. Since ozone in clean air has a lifetime of only a few hours, this phenomenon is a measure of the effect and the persistence of both VOC and NOx.

Differences in the distance estimates between the emission of NOx and the generation of ozone may be related to differences in plume transport (wind) speeds as well as other meteorological and air quality factors. It is important to note that, under the right conditions, power plant plumes may travel relatively long distances overnight with little loss of VOC, NO and NO_2 . These pollutants can thus be available to participate in photochemical reactions at distant locations on the following day.[41] Figure 1 shows a map of NOx concentration drawn by the Center for Air Pollution Impact and Trend Analysis (CAPITA) at Washington University in St. Louis and reported to the Ozone Transport Assessment Group, a national workgroup that addressed the problem of ground-level ozone (smog) and the long-range transport of air pollution across the Eastern United States. OTAG was a partnership among the EPA, the Environmental Council of the States (ECOS) and various industry and environmental groups with the goal of developing a thoughtful assessment and a consensus agreement for reducing ground-level ozone and the

pollutants that cause it. The animated version of Figure 1 shows the trajectory of NOx emissions moving with the weather over an 8 day period.

Figure 2 is a map of ozone concentration that shows the same trajectory over the 8 day period. The animated version shows concentrations of both NOx and ozone moving with the weather for several hundred miles.[5]

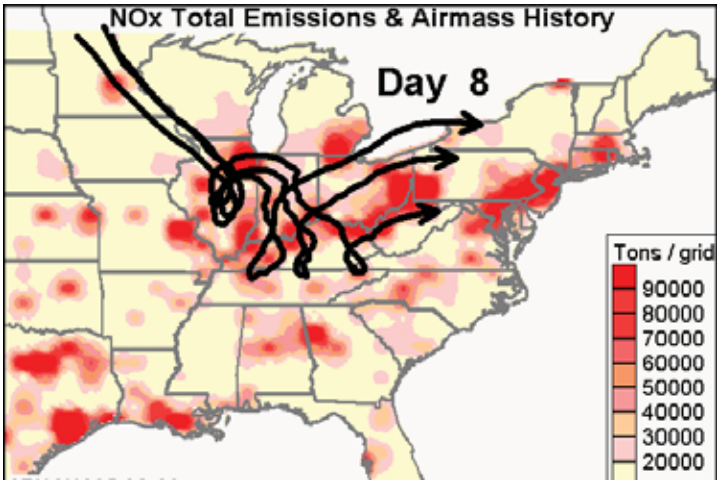

Figure 2 NOx Map

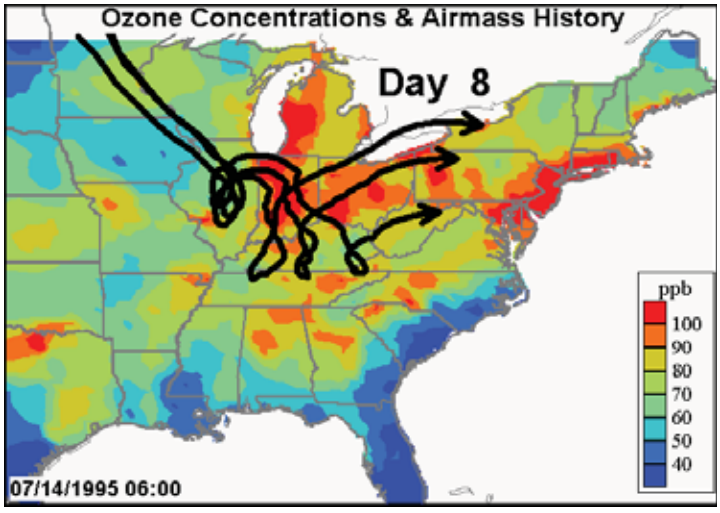

Figure 3 Ozone Map

Ozone is the primary constituent of smog. Between 1970 and 1990, we in the United States have tried to control ozone primarily by controlling the emissions of VOC. However, we have had mixed results, for although some areas reduced their VOC emissions and attained their ozone goals, others have not. It now appears that the communities that failed to meet their ozone goals

may not be completely at fault, for they appear to be affected by NOx and VOC emissions in the air coming to them. To meet the ozone NAAQS, EPA must now regulate emissions of NOx regionally.

ARE THERE OTHER NOx RELATED ISSUES?

Yes. Nutrient enrichment problems (eutrophication) occur in bodies of water when the availability of either nitrates or phosphates become too large. As a result, the ratios of nitrogen to phosphorus, silicon, and iron and other nutrients are altered. This alteration may induce changes in phytoplankton, produce noxious or toxic brown or red algal blooms (which are called "red tides"), or stimulate other plant growth. The algal blooms and plant growth produce a shadow and cause the death of other plants in the water, which depletes the oxygen content of the water (hypoxia) when the plants die, sink, and decay. Such eutrophication can make the bottom strata of water unihabitable for both marine animals (such as fish and shellfish) and aquatic plants. It can progress to virtually the complete depth of the water. It is estimated that between 12% and 44% of the nitrogen loading of coastal water bodies comes from the air.[40] Inland lakes are also affected in this way.

Another dimension of the problem is that high temperature combustion can convert sulfur in fuel to SO_2 and SO_3. While SO_2 is toxic and forms sulfurous acid when dissolved in water, SO_3 is both toxic and hygroscopic (moisture absorbing) and forms sulfuric acid by combining with moisture in the atmosphere. SO_2 and SO_3 form sulfites and sulfates when their acids are neutralized. Both of these acids can form solid particles by reacting with ammonia in air. SO_2 and SO_3 also contribute to pH (acidity) changes in water, which can adversely affect both land and aquatic life. Therefore, both NOx and SOx from combustion can kill plants and animals.

CAPITA has shown that there are about equal amounts by weight of sulfate/sulfite, nitrate and organic particles making up 90% of Particulate Matter less than 2.5 microns in aerodynamic diameter (PM-2.5). This was confirmed by Brigham Young University researchers. The Six Cities Study, published in the *New England Journal of Medicine* in 1990, has shown that illness and premature death are closely correlated with the amount of PM-2.5 in the air. Therefore, there is epidemiological data indicting nitrogen oxides, sulfur oxides, and/or organic compounds as PM-2.5 aerosols. There is currently no evidence that separately examines the health effects of each of these substances. PM-2.5 usually appear as smog, smoke, white overcast, haze, or fog which does not clear when air warms up. Brown smog is colored by nitrogen dioxide.

Because the nitric acid, sulfurous acid and sulfuric acid react with ammonia in air to form solid crystals that are much smaller than 2.5 microns and can be nucleation sites for particle growth, we need to be concerned about each of these pollutants. Some research indicates that even insoluble particles much smaller than 2.5 microns in size can exhibit severe toxic effects.[38] The smallest particles that have shown toxicity have a diameter of about 3% to 5% of the wavelength of any color of visible light. Therefore, these particles are too small to even scatter light and cannot even be detected optically.

Acid deposition occurs from airborne acidic or acidifying compounds, principally sulfates (SO_4^{-2}) and nitrates (NO_3^{-1}), that can be transported over long distances before returning to earth. This occurs through rain or snow (wet deposition), fog or cloud water (cloud deposition), or transfer of gases or particles (dry deposition). While severity of damage depends on the sensitivity of the receptor, acid deposition and NOx "represent a threat to natural resources, ecosystems, visibility, materials, and public health."(section 401(a)(1) of the Clean Air Act).[40]

WHAT ABATEMENT AND CONTROL PRINCIPLES APPLY?

NOx abatement and control technology is a relatively complex issue. We shall try to provide a structure to the spectrum of NOx pollution prevention and control technologies by first giving the principles that are used. Then we shall describe the more successful pollution prevention and emission control technologies and strategies.

Please note that abatement and control of NOx from nitric acid manufacturing and "pickling" baths differs from abatement and control at combustion sources. Combustion sources all have NOx in a large flow of flue gas, while nitric acid manufacturing plants and pickling baths try to contain the NOx. Wet scrubbers (absorbers) can control NOx emissions from acid plants and pickling, and can use either alkali in water, water alone, or hydrogen peroxide as the liquid that captures the NOx.[3] The wet scrubber operates by liquid flowing downward by gravity through a packing medium, opposed by an upward flow of gas. Scrubbers operate on the interchange of substances between gas and liquid. This requires that the height of the absorber, type of packing, liquid flow, liquid properties, gas properties, and gas flow should collectively cause a scrubber to have the desired control efficiency. Chapter 9 of the OAQPS Control Cost Manual provides guidance on the application, sizing, and cost of these scrubbers (referred to as gas absorbers). Also, Table 16 in this Bulletin presents some information for non-combustion NOx sources. Other then that, non-combustion NOx sources are not addressed in this Bulletin.

For combustion sources, this Bulletin defines abatement and emission control principles and states the Destruction or Removal Efficiency (DRE) that each successful technology is capable of achieving. The effectiveness of pollution prevention measures in reducing NO and NO_2 generation also is expressed in terms of relative DRE; i.e., the amount NOx generation is reduced by using a prevention technology compared to NOx generation when not using that technology. Then, specific boiler types and combustion systems and applicable NOx technologies for each system are discussed. Finally, the cost of these technologies is considered.

Many new combustion systems incorporate NOx prevention methods into their design and generate far less NOx then similar but older systems. As a result, considering DRE (even a relative DRE) for NOx may be inappropriate. Comparing estimated or actual NOx emissions from a new, well-designed system to NOx emitted by a similar well-controlled and operated older system may be the best way of evaluating how effectively a new combustion system minimizes NOx emissions.

Table 2 lists principles or methods that are used to reduce NOx. Basically there are six

principles, with the seventh being an intentional combination of some subset of the six.

Table 2. NOx Control Methods [6,7]

Abatement or Emission Control Principle or Method	Successful Technologies	Pollution Prevention Method (P2) or Add-on Technology (A)
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning Low NOx Burners (LNB) Combustion Optimization Burners Out Of Service (BOOS) Less Excess Air (LEA) Inject Water or Steam Over Fire Air (OFA) Air Staging Reduced Air Preheat Catalytic Combustion	P2 P2 P2 P2 P2 P2 P2 P2 P2 P2 P2
2.Reducing residence time at peak temperature	Inject Air Inject Fuel Inject Steam	P2 P2 P2
3. Chemical reduction of NOx	Fuel Reburning (FR) Low NOx Burners (LNB) Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)	P2 P2 A A
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor Inject Oxidant	A A
5. Removal of nitrogen	Oxygen Instead Of Air Ultra-Low Nitrogen Fuel	P2 P2
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	A A
7. Combinations of these Methods	All Commercial Products	P2 and A

Method 1. Reducing Temperature -- Reducing combustion temperature means avoiding the stoichiometric ratio (the exact ratio of chemicals that enter into reaction). Essentially, this technique dilutes calories with an excess of fuel, air, flue gas, or steam. Combustion controls use different forms of this technique and are different for fuels with high and low nitrogen content.

Control of NOx from combustion of high nitrogen content fuels (e.g., coal) can be understood by the net stoichiometric ratio. Control of the NOx from combustion of low nitrogen fuels (such as gas and oil) can be seen as lean versus rich fuel/air ratios. Either way, this technique avoids the ideal stoichiometric ratio because this is the ratio that produces higher temperatures that generate higher concentrations of thermal NOx.

Combustion temperature may be reduced by: (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit temperature by diluting energy input; (3) injecting cooled oxygen-depleted flue gas into the combustion air to dilute energy; (4) injecting cooled flue gas with added fuel; or (5) injecting water or steam. Low-NOx burners are based partially on this principle.[8,9,10] The basic technique is to reduce the temperature of combustion products with an excess of fuel, air, flue gas, or steam. This method keeps the vast majority of nitrogen from becoming ionized (i.e., getting a non-zero valence).

Method 2. Reducing Residence Time -- Reducing residence time at high combustion temperatures can be done by ignition or injection timing with internal combustion engines. It can also be done in boilers by restricting the flame to a short region in which the combustion air becomes flue gas. This is immediately followed by injection of fuel, steam, more combustion air, or recirculating flue gas. This short residence time at peak temperature keeps the vast majority of nitrogen from becoming ionized. This bears no relationship to total residence time of a flue gas in a boiler.

Method 3. Chemical Reduction of NOx – This technique provides a chemically reducing (i.e., reversal of oxidization) substance to remove oxygen from nitrogen oxides. Examples include Selective Catalytic Reduction (SCR) which uses ammonia, Selective Non-Catalytic Reduction (SNCR) which use ammonia or urea, and Fuel Reburning (FR). Non-thermal plasma, an emerging technology, when used with a reducing agent, chemically reduces NOx. All of these technologies attempt to chemically reduce the valence level of nitrogen to zero after the valence has become higher.[11] Some low-NOx burners also are based partially on this principle.

Method 4. Oxidation of NOx -- This technique intentionally raises the valence of the nitrogen ion to allow water to absorb it (i.e., it is based on the greater solubility of NOx at higher valence). This is accomplished either by using a catalyst, injecting hydrogen peroxide, creating ozone within the air flow, or injecting ozone into the air flow. Non-thermal plasma, when used without a reducing agent, can be used to oxidize NOx. A scrubber must be added to the process to absorb N_2O_5 emissions to the atmosphere. Any resultant nitric acid can be either neutralized by the scrubber liquid and then sold (usually as a calcium or ammonia salt), or collected as nitric acid to sell to customers.[12, 49]

Method 5. Removal of nitrogen from combustion -- This is accomplished by removing nitrogen as a reactant either by: (1) using oxygen instead of air in the combustion process; or (2) using ultra-low nitrogen content fuel to form less fuel NOx. Eliminating nitrogen by using oxygen tends to produce a rather intense flame that must be subsequently and suitably diluted. Although Method 2 can lower the temperature quickly to avoid forming excessive NOx, it cannot

eliminate nitrogen oxides totally if air is the quench medium. Hot flue gas heats the air that is used to quench it and this heating generates some thermal NOx. This method also includes reducing the net excess air used in the combustion process because air is 80% nitrogen. Using ultra-low-nitrogen content fuels with oxygen can nearly eliminate fuel and prompt NOx.[13]

Method 6. Sorption, both adsorption and absorption -- Treatment of flue gas by injection of sorbents (such as ammonia, powdered limestone, aluminum oxide, or carbon) can remove NOx and other pollutants (principally sulfur). There have been successful efforts to make sorption products a marketable commodity. This kind of treatment has been applied in the combustion chamber, flue, and baghouse. The use of carbon as an adsorbent has not led to a marketable product, but it is sometimes used to limit NOx emissions in spite of this. The sorption method is often referred to as using a dry sorbent, but slurries also have been used. This method uses either adsorption or absorption followed by filtration and/or electrostatic precipitation to remove the sorbent.

Method 7. Combinations of these methods -- Many of these methods can be combined to achieve a lower NOx concentration than can be achieved alone by any one method. For example, a fuel-rich cyclone burner (Method 1) can be followed by fuel reburn (Method 3) and over-fire air (Method 1). This has produced as much as a 70% reduction in NOx.[55] Other control technologies that are intended to primarily reduce concentrations of sulfur also strongly affect the nitrogen oxide concentration. For example, the SOx-NOx-ROx-Box (SNRB) technology uses a limestone sorbent in the flue gas from the boiler to absorb sulfur. This is followed by ammonia injection and SCR using catalyst fibers in the baghouse filter bags. The sulfur is recovered from the sorbent and the sorbent regenerated by a Claus process. This has demonstrated removal of up to 90% of the NOx along with 80% of the SOx.[39, 42] EBARA of Japan reported that an electron beam reactor with added ammonia removed 80% of the SO_2 and 60% of the NOx for a utility boiler in China.[54] FLS Milo and Sons reported at the same symposium that 95% of the SO_2 and 70%-90% of the NOx were removed in several demonstrations of their SNAP technology, which is based upon an aluminum oxide adsorber with Claus regeneration.[56]

WHAT ABATEMENT TECHNOLOGIES ARE AVAILABLE?

In this report existing NOx abatement technologies are divided into two categories, external combustion applications (e.g., boilers, furnaces and process heaters) and internal combustion applications (e.g., stationary internal combustion engines and turbines). These categories are further subdivided into pollution prevention (which reduces NOx generation) and add-on control technologies (which reduces NOx emissions).

EXTERNAL COMBUSTION

For external combustion applicable technologies are shown in Table 3 (based on Table 2 in Select the Right NOx Control Technology, Stephen Wood, Chemical Engineering Progress, January 1994).

Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Less Excess Air (LEA)	Reduces oxygen availability	Easy modification	Low NOx reduction	High CO Flame length Flame stability	All fuels
Off Stoichiometric a. Burners Out of Service (BOOS) b. Over Fire Air (OFA)	staged combustion	Low cost No capital cost for BOOS	a. Higher air flow for CO b. high capital cost	Flame length Fan capacity Header pressure	All fuels Multiple burners for BOOS
Low NOx Burner (LNB)	Internal staged combustion	Low operating cost Compatible FGR	Moderately high capital cost	Flame length Fan capacity Turndown stability	All fuels
Flue Gas Recirculation (FGR)	<30% flue gas recirculated with air, decreasing temperature	High NOx reduction potential for low nitrogen fuels	Moderately high capital cost and operating cost Affects heat transfer and system pressures	Fan capacity Furnace pressure Burner pressure drop Turndown stability	All fuels Low nitrogen fuels
Water/Steam Injection	Reduces flame temperature	Moderate capital cost NOx reduction similar to FGR	Efficiency penalty Fan power higher	Flame stability Efficiency penalty	All fuels as Low nitrogen fuels
Reduced Air Preheat	Air not preheated, reduces flame temperature	High NOx reduction potential	Significant efficiency loss (1% per 40°F)	Fan capacity Efficiency penalty	All fuels Low nitrogen fuels
Selective Catalytic reduction (SCR) (add-on technology)	Catalyst located in the air flow, promotes reaction between ammonia and NOx	High NOx removal	Very high capital cost High operating cost Catalyst siting Increased pressure drop Possible water wash required	Space requirements Ammonia slip Hazardous waste Disposal	All fuels

Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Selective Non-Catalytic Reduction (SNCR) (add-on technology) a. urea b. ammonia	Inject reagent to react with NOx	a. Low capital cost Moderate NOx removal Non-toxic chemical b. Low operating cost Moderate NOx removal	a. Temperature dependent NOx reduction less at lower loads b. Moderately high capital cost Ammonia storage, handling, injection system	a. Furnace geometry Temperature profile b. Furnace geometry Temperature profile	All fuels
Fuel Reburning	Inject fuel to react with NOx	Moderate cost Moderate NOx removal	Extends residence time	Furnace temperature profile	All fuels (pulverized solid)
Combustion Optimization	Change efficiency of primary combustion	Minimal cost	Extends residence time	Furnace temperature profile	Gas Liquid fuels
Catalytic Combustion	Catalyst causes combustion to be at low temperature	Lowest possible NOx	Very high capital cost High operating cost Catalyst siting	Space requirements Disposal	Gas Liquid fuels
Non-Thermal Plasma	Reducing agent ionized or oxidant created in flow	Moderate cost Easy siting High NOx removal	Fouling possible Ozone emission possible	Uses electrical power	All fuels
Inject Oxidant	Chemical oxidant injected in flow	Moderate cost	Nitric acid removal	Add-on	All fuels
Oxygen instead of Air	Uses oxygen to oxidize fuel	Moderate to high cost Intense combustion	Eliminates prompt NOx Furnace alteration	Equipment to handle oxygen	All fuels
Ultra-Low Nitrogen Fuel	Uses low -nitrogen fuel	Eliminates fuel NOx No capital cost	Slight rise in operating cost	Minimal change	All ultra-low nitrogen fuels

Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Use Sorbents (add-on technology) in: a. Combustion b. Duct to Baghouse c. Duct to Electrostatic Precipitator	Use a chemical to absorb NOx or an adsorber to hold it	Can control other pollutants as well as NOx Moderate operating cost	Cost of handling sorbent Space for the sorbent storage and handling	Add-on	All fuels
Air Staging	Admit air in separated stages	Reduce peak combustion temperature	Extend combustion to a longer residence time at lower temperature	Adds ducts and dampers to control air Furnace modification	All fuels
Fuel Staging	Admit fuel in separated stages	Reduce peak combustion temperature	Extend combustion to a longer residence time at lower temperature	Adds fuel injectors to other locations Furnace modification	All fuels

EXTERNAL COMBUSTION: POLLUTION PREVENTION METHODS

LESS EXCESS AIR (LEA)

Excess air flow for combustion has been correlated to the amount of NOx generated. Limiting the net excess air flow to under 2% can strongly limit NOx content of flue gas. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.[43]

BURNERS OUT OF SERVICE (BOOS)

Multiple-burner equipment can have part of an array of burners with some "burners out of service" (not feeding fuel, but supplying air or flue gas). This allows the burners around them to supply fuel and air to air or flue gas flowing from the BOOS. The result is combustion by stages with temperature always lower than when all burners are in service. Thus, thermal NOx is lower. The degree to which NOx generation is reduced depends upon the spatial relationship of the BOOS to the other burners.[44]

OVER FIRE AIR (OFA)

When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the temperature is held down. After all other stages of combustion, the remainder of the fuel is oxidized in the over fire air. This is usually not a grossly excessive amount of air.

LOW NOx BURNERS (LNB)

A LNB provides a stable flame that has several different zones. For example, the first zone can be primary combustion. The second zone can be Fuel Reburning (FR) with fuel added to chemically reduce NOx. The third zone can be the final combustion in low excess air to limit the temperature. There are many variations on the LNB theme of reducing NOx. The LNB has produced up to 80% DRE.[17,18, 32, 33] This can be one of the least expensive pollution prevention technologies with high DRE. LNB have had problems with designs that had flame attaching to the burners, resulting in a need for maintenance. We believe that these design problems should now be a thing of the past.

FLUE GAS RECIRCULATION (FGR)

Recirculation of cooled flue gas reduces temperature by diluting the oxygen content of combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the NOx concentration that is generated. If combustion temperature is held down to below 1,400°F, the thermal NOx formation will be negligible.[50]

WATER OR STEAM INJECTION

Injection of water or steam causes the stoichiometry of the mixture to be changed and adds steam to dilute calories generated by combustion. Both of these actions cause combustion temperature to be lower. If temperature is sufficiently reduced, thermal NOx will not be formed in as great a concentration.

REDUCED AIR PREHEAT

Air is usually preheated to cool the flue gases, reduce the heat losses, and gain efficiency. However, this can raise the temperature of combustion air to a level where NOx forms more readily. By reducing air preheat, the combustion temperature is lowered and NOx formation is suppressed. This can lower efficiency, but can limit NOx generation.

FUEL REBURNING (FR)

Recirculation of cooled flue gas with added fuel (this can be natural gas, pulverized coal, or even oil spray) causes dilution of calories, similar to FGR, and primary combustion temperature can be lowered. Also, when added as a secondary combustion stage, the presence of added fuel chemically reduces newly generated NOx to molecular nitrogen. Added fuel is only partially consumed in reducing NOx and burning is completed in a later stage using either combustion air nozzles or over-fire-air. This technique has been demonstrated to be effective with residence times from 0.2 seconds to 1.2 seconds and has achieved up to 76% DRE. [17]

COMBUSTION OPTIMIZATION

Combustion optimization refers to the active control of combustion. In a natural gas fired boiler, by decreasing combustion efficiency from 100% to 99%, NOx generation dropped to a much more acceptable level.[14,15] For coal-fired boilers a 20% to 60% reduction in NOx has been experienced. These active combustion control measures seek to find an optimum combustion efficiency and to control combustion (and hence emissions) at that efficiency. Another approach uses a neural network computer program to find the optimum control point.[16] Still another approach is to use software to optimize inputs for the defined output.[52,53]

One vendor decreases the amount of air that is pre-mixed with fuel from the stoichiometric ratio (ratio that produces the hottest flame) to lengthen the flame at the burner and reduce the rate of heat release per unit volume. This can work where the boiler tubes are far enough away from the burner. Carbon monoxide, unburned fuel, and partially burned fuel that result can then be subsequently oxidized in over-fire-air at a lower temperature. Combustion must be optimized for the conditions that are encountered. 50% DRE has been reported.[14]

AIR STAGING

Combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that

produces a reducing flame. The second stream is injected downstream of the flame and makes the net ratio slightly excess air compared to the stoichiometric ratio. DRE up to 99% have been reported.[51]

FUEL STAGING

This is staging of combustion using fuel instead of the air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel to air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be only slightly oxidizing. Excess fuel in primary combustion dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NOx to N_2. This is reported to achieve a 50% DRE.[51]

OXYGEN INSTEAD OF AIR FOR COMBUSTION

An example of this is a cyclone burner where the flame is short and intense. Excess fuel air or steam, injected just after the combustion chamber per Method 2 is sufficient to rapidly quench the flue gas to below NOx formation temperature. Combustion can then be completed in over-fire air. Oxygen can now be separated from air at a low enough cost to make this economical.[13] This technique has reduced NOx by up to 20%[23] in burners using conventional fuel. This technique also is usable with low-NOx burners to prevent the prompt NOx from being formed.

INJECTION OF OXIDANT

The oxidation of nitrogen to its higher valence states makes NOx soluble in water. When this is done a gas absorber can be effective. Oxidants that have been injected into the air flow are ozone, ionized oxygen, or hydrogen peroxide. Non-thermal plasma generates oxygen ions within the air flow to achieve this. Other oxidants have to be injected and mixed in the flow. Nitric acid can be absorbed by water, hydrogen peroxide, or an alkaline fluid. Calcium or ammonia dissolved in the water can make an alkaline fluid that will react with nitric and sulfuric acids to produce a nitrate or sulfate salt that can be recovered. Alternatively, using water or hydrogen peroxide to absorb NOx can provide nitric acid for the commercial market.

CATALYTIC COMBUSTION

Use of a catalyst to cause combustion to occur below NO formation temperatures can provide a suitable means of limiting temperature. This technique is not used often because it is very load sensitive. However, where it is used, catalytic combustion can achieve less than a 1 ppm concentration of NOx in the flue gas.

ULTRA-LOW NITROGEN FUELS

These fuels can avoid NOx that results from nitrogen contained in conventional fuels. The result can be up to a 70% reduction in NOx emissions.[43] Now there are ultra-low-nitrogen liquid fuel

oils. These oils contain 15-20 times less nitrogen than standard No. 2 fuel oil. This oil is now commercially available and competitively priced. Ultra-low-nitrogen oil is most frequently used in Southern California where the air pollution is particularly a problem. Natural gas can be considered a low-nitrogen fuel. Coke (the quenched char from coal) can also be an ultra-low-nitrogen fuel because nitrogen in the volatile fraction of the coal is removed in making coke.

NON-THERMAL PLASMA

Using methane and hexane as reducing agents, non-thermal plasma has been shown to remove NOx in a laboratory setting with a reactor duct only 2 feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NOx and achieved a 94% DRE. There are indications that an even higher DRE can be achieved. A successful commercial vendor uses ammonia as a reducing agent to react with NOx in an electron beam generated plasma. Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor could also be used without reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid.

EXTERNAL COMBUSTION: ADD-ON CONTROL TECHNOLOGY

Add-on controls are applicable to a broad range of sources and fuels. This differs from the pollution prevention techniques listed above in that the prevention techniques must be adapted to the circumstances of their use.

SELECTIVE CATALYTIC REDUCTION (SCR)

SCR uses a catalyst to react injected ammonia to chemically reduce NOx. It can achieve up to a 94% DRE[34] and is one of the most effective NOx abatement techniques. However, this technology has a high initial cost. In addition, catalysts have a finite life in flue gas and some ammonia "slips through" without being reacted. SCR has historically used precious metal catalysts, but can now also use base-metal and zeolite catalysts. The base-metal and zeolite catalysts operate at much different temperatures then the precious metal catalysts.[11]

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR ammonia or urea is injected within a boiler or in ducts in a region where temperature is between 900°C and 1100°C. This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst or non-thermal plasma. This temperature "window" – which is reported differently by various authors -- is important because outside of it either more ammonia "slips" through or more NOx is generated than is being chemically reduced. The temperature "window" is different for urea and ammonia. Reduction of the NOx by SNCR can have up to a 70% DRE.[23,35,43]

SORPTION – BOTH ADSORPTION AND ABSORPTION

Several methods are used to inject and remove adsorbent or absorbent. One method sprays dry powdered limestone into the flue gas. The limestone then reacts with both sulfuric acid and nitric acid. There also is a spray dryer approach that sprays a slurry of powdered limestone and aqueous ammonia into the flue gas. The limestone preferentially reacts with the sulfur while the ammonia preferentially reacts with the NOx. In-duct injection of dry sorbents is another example of this technique and can reduce pollutants in three stages: (1) in the combustion chamber, (2) in the flue gas duct leading to the baghouse, and (3) in the flue gas duct leading to the electrostatic precipitator. The by products formed by sorption are gypsum (calcium sulfate) that is sold to make wallboard, and ammonium nitrate that can be sold to make either an explosive or a fertilizer. Sorption is reported to have up to a 60% DRE.[23, 31] Another version uses carbon injected into the air flow to finish the capture of NOx. The carbon is captured in either the baghouse or the ESP just like other sorbents. There are many absorbents and adsorbents available.

COMBINED TECHNOLOGY APPROACHES

Very seldom is only one method or principle used alone. The choice depends upon the type of combustion system, type of boiler or other energy conversion device, and type of fuel used. Available technologies will be narrowed by consideration of turndown ratio, stability of combustion, availability or access to burners, air supply controls, fuel impurities, and cost among other factors.

There are many examples and here are a few of them. Selective catalytic reduction of NOx to N_2 can be followed by selective oxidation of sulfur dioxide to sulfur trioxide. Then sulfuric acid is formed followed by scrubbing sulfuric acid from the flue gas.[30]

LNB can be used in conjunction with SCR or SNCR to achieve a greater overall DRE than any of these can achieve alone. Water/steam injection can be used with SCR to achieve a DRE greater than SCR can achieve alone. Fuel reburning and SCR can be used together as well as separately, to get the maximum NOx reduction.[57]

INTERNAL COMBUSTION

Now we turn to internal combustion, which usually occurs at elevated pressures. Again, we divide the technologies between pollution prevention techniques and add-on technologies. This is shown in Table 4.

These techniques can be used in combination. Pollution prevention techniques do not have to be used separately. Add-on techniques could be used sequentially after a pollution prevention technique when they do not impose conflicting demands on the process.

Table 4. Internal Combustion NOx Limiting Technologies

Pollution Prevention	Add-On Control
Low-NOx Burners (LNB)	Selective Catalytic Reduction (SCR)
Steam/Water Injection	Selective Non-Catalytic Reduction (SNCR)
Catalytic Combustion	Non-Selective Catalytic Reduction (NSCR)
Air-Fuel Ratio and Ignition Type	Non-Thermal Plasma
Pre-Stratified Charge	
Lean Burn	

INTERNAL COMBUSTION: POLLUTION PREVENTION METHODS

LOW NOx BURNERS (LNB)

Combining the use of LNB with closely controlled air/fuel ratio and water/steam injection can yield emissions as low as 10 ppm from gas turbines.[46]

STEAM/ WATER INJECTION

To reduce combustion temperature, steam or water can be mixed with the air flow. This lowers combustion temperature to below 1,400°F to limit NOx generation to about 40 ppm.[46] This can cause the concentration of CO and unburned hydrocarbons emitted from a turbine to be increased. However, these can be burned by either a catalyst bed, afterburner, or another stage of combustion. This otherwise wasted fuel and heat can also be recovered in co-generation boilers.

CATALYTIC COMBUSTION

A catalyst is used to react fuel with air at a lower temperature than normal combustion at which generation of significant amounts of NOx does not occur. Emissions under 1 ppm NOx have been reported.[46] However, if this combustion is for a turbine, turbine efficiency may depend upon achieving a higher temperature. When a catalyst is present, you also need to assure that NOx will not be formed at the combustion temperature that results.

This technology has a relatively high capital and operation and maintenance cost because there is both a substantial initial investment and a replacement cost for the catalyst. The need for replacement and, therefore, replacement cost are usually driven by impurities in the fuel. However, catalytic combustion generates possibly the lowest level of thermal NOx.

AIR-FUEL RATIO AND IGNITION TYPE

For internal combustion reciprocating engines, retardation of injection or spark ignition, or an air-fuel ratio that departs from stoichiometric conditions will reduce peak temperature. Lower peak temperature will limit the amount of NOx formation. This technique can achieve up to 50% control efficiency.[19, 48]

When a three-way catalyst is used for spark ignition engines, exhaust gas must have no more than 0.5% oxygen. This technique can be up to 98% effective.

The use of plasma ignition (an alternating current or AC system) instead of a direct current (DC) spark ignition system can also allow a greater fuel-lean departure from the stoichiometric ratio. NOx emissions from internal combustion engines using plasma ignition have been reported to be reduced by up to 97%.[20,21, 45]

Delaying injection of fuel in a compression ignition (diesel) engine can reduce the NOx emissions. The amount of this reduction will depend upon the engine, valving, and fuel. Excessive timing retard can cause combustion instability or misfire.[48] However, some claims of high effectiveness are to be found with ostensibly excessive retard.

PRE-STRATIFIED CHARGE (PSC)

PSC refers to an engine equipped with a pre-combustion chamber that receives a rich enough air/fuel mixture to ignite dependably. This pre-combustion chamber fires a jet of flame into the main combustion chamber (cylinder). The main combustion chamber has a fuel-lean mixture that needs pre-combustion flame to ignite it reliably. The injected flame also produces a swirl in the main combustion chamber that acts like stratified charge combustion. This dependably ignites the lean main cylinder mixture. The PSC can achieve NOx emissions of 2 grams/horsepower-hour (g/hp-hr) or 140 ppm.[48]

LEAN BURN

Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NOx emissions. These can achieve less than 1.0 gram/brake horsepower-hour according to the RACT-BACT-LAER Clearinghouse (RBLC) (http://www.epa.gov/ttn/catc, then select RBLC).

INTERNAL COMBUSTION ADD-ON CONTROL TECHNOLOGY

SELECTIVE CATALYTIC REDUCTION (SCR)

As with boilers, SCR can be used to obtain up to a 90% DRE of NOx. When used with a LNB or steam/water injection, NOx can be reduced to 5-10 ppm.[46] With compression ignition engines, zeolite catalysts achieve a DRE of 90+%, while base-metal catalysts can achieve a 80% to 90% DRE.[48]

NON-SELECTIVE CATALYTIC REDUCTION (NSCR)

NSCR is the same technique used in automobile applications as a three-way catalytic converter. It does not require injection of a reducing agent because it uses unburned hydrocarbons as a reducing agent. The catalyst requires that exhaust have no more than 0.5% oxygen. This technique uses a fuel rich mixture that, combined with back pressure from exhaust flow through the catalyst, increases the brake specific fuel consumption of the engine. However, NOx control of 90% to 98% can be achieved.[48]

NON-THERMAL PLASMA REACTORS

This approach uses a non-thermal plasma to ionize ammonia, urea, hexane, methane or other reducing agents injected into a flue gas. Combined with the effect of temperature, non-thermal plasma ionizes the reducing agent that reacts with nitrogen oxides achieving a 94% DRE. This decreases the amount of reducing chemicals that "slips" through unreacted.[20,44] The use of non-thermal plasma was developed to ionize pollutants and act as a catalyst to control NOx in diesel exhaust.[36]

DO FUELS AND COMBUSTION TYPE AFFECT ABATEMENT?

Yes they do. Here again, we find a spectrum of types, almost enough to make every gas turbine, internal combustion engine, boiler, or furnace seem unique. The type of fuel can vary with the vein of the mine from which coal was obtained, the well in the oilfield from which crude oil came, the refinery for petroleum based fuels, or the supplier of natural gas. Thus the concentration of impurities will vary between sources, refineries, and suppliers. Even "natural gas" (methane) may contain some "supplier gas" (propane, butane, and carbon monoxide) which will cause the composition of "natural gas" to vary.

The type of combustion system (low-NOx burner, over-fire air, tangential firing, wall firing, etc) also will sometimes limit options. Each type of boiler, each type of fuel, each combustion system, and each construction of a boiler puts constraints on what is possible. It is not possible to treat each combination of combustion system and fuel in detail in this Technical Bulletin; however, we will try to show the picture while painting with broad strokes.

The choice of fuel and combustion system often depends upon: (1) what can or cannot be adjusted; (2) whether ducts are suitable for sorption; (3) what the effect on boiler maintenance will be; (4) the temperature profile in the flow: (5) how the combustion system can be modified; (6) what types of burners can be used; and (7) what can either be added or modified. The list does not end there, but continues. Let us consider some fuels with these limitations in mind.

SOLID FUELS

In burning a solid fuel (such as coal), combustion control is achieved by first getting the primary burner to gasify the volatile fraction of a fuel. The volatile fraction is carried away from char by

air flow, oxidized in the air flow, and becomes flue gas. Char needs more combustion air to burn and provide further heat, part of which is used to volatilize additional fuel. To control combustion temperature, you traditionally would limit combustion air through the char fraction. The volatile fraction is oxidized in over-fire-air or a secondary stage of burner and must have its air separately controlled. The balance of combustion air between these stages must be adjusted for composition of fuel being used, boiler loading, and transient loads. Because all of these parameters will vary continually, provisions to make balancing adjustments dynamically are recommended.

Pulverized coal can be burned similar to oil. The flame is usually well defined and, depending on particle size, char may remain in suspension in flue gas throughout burning. The volatile fraction burns in air even as char is burned. If the particles are too coarse, char will continue burning on its trajectory after leaving the flame, but will stop burning at some point. The trade jargon for this is " unburned carbon (UBC)," "carbon in the ash (CIA)," or "loss of ignition (LOI)." These terms refer to carbon in char that does not burn along the trajectory. UBC is minimized by grinding particles finer and classifying particles so that larger ones are returned to the roller mill or grinder. Particles will become fly ash if they are small enough. UBC ranging from 0.5% to 5% is considered acceptable. Therefore, particle size at ignition is important. The major concerns are to control stoichiometry and combustion temperature to minimize unburned carbon in ash.

Biomass is another solid fuel, but burning biomass char is less of a concern than with coal. Biomass cannot be pulverized to small particles, but can burn to ash in a short time. As with the burning of all char, ash and fly ash are problems, but can be treated with a slag tap or ash pit, baghouse, and/or electrostatic precipitator.

LIQUID FUELS

Liquid fuels burn like the volatile fraction of solid fuel provided that the droplets are small enough. Liquid fuels usually have less nitrogen content than solid fuels. Combustion of liquids and gases can be controlled much more readily than char from solid fuel because combustion is less dependent on the history of the past few minutes of demand. Combustion is also completed essentially without residual ash. The fuel-air ratio can be used to control combustion temperature and can be adjusted to minimize NOx generation. The flame can be well-defined and combustion is essentially completed within the flame. Therefore, burning oil or liquid-from-coal or liquid-from-gas is different from burning coal because there is usually less nitrogen in the fuel, a lack of char, complete burning within the flame and a lack of ash.

SEMI-SOLID FUELS

Semi-solid fuels are residuals from refineries. They are not clean burning like distillates and often are not even liquid at room temperature. Many impurities typically found in crude oil are concentrated in semi-solid residual fuel. These fuels can contain more nitrogen than coal, but usually contain less sulfur.[50] Therefore, semi-solid fuels are intermediate between coal and oil. They often have somewhat less impurities than coal (although they can have more impurities),

but they do produce ash.

GAS FUEL

Natural gas is desulfurized before it is sent in a pipeline. Therefore, natural gas has almost no sulfur, essentially no impurities, and no ash. The only thing that varies is heat content per cubic meter. This variance is caused by natural gas producers supplementing natural gas with propane, liquified petroleum gas (butane), carbon monoxide, or other gaseous fuel. As a result, air to fuel ratio must be controllable to allow for changes in the stoichiometric ratio.

COMBUSTION SYSTEMS

To take advantage of a specific NOx abatement technology, a combustion system must either have certain features in place, or needed system modifications must be technically and economically feasible. Therefore, when identifying applicable pollution prevention and emission control technologies, we must first consider combustion system design. The major types of combustion systems are shown in Table 5.[23]

Table 5. Common Combustion Systems

Type of Combustion Unit	Fuel
Dry bottom boilers - wall-fired, front-fired or opposed-fired	pulverized coal, gas, or liquid
Dry bottom boilers - tangentially fired	pulverized coal, gas, or liquid
Wet bottom (slag tap) boilers - cyclone-type burners	pulverized coal, gas, or liquid
Fluidized bed	coal
Stokers with traveling grate.	crushed coal
Stokers with spreader grate	crushed coal.
Gas turbines	gas and liquid
Internal combustion engines	gas and liquid

Each NOx abatement technology has different implementations, development histories, and, therefore, commercial status. Selection of a technology must occur after an engineering study to determine technical and economic feasibility of each NOx technology. This includes how each technology can be implemented and its cost. Options may be limited by inability to adjust combustion system air flow appropriately, ducts that are at the wrong temperature, or ducts that

are too short to provide adequate mixing. These problems can be solved, but may require too much modification to make them economical.

DRY BOTTOM BOILERS - WALL-FIRED, FRONT-FIRED or OPPOSED-FIRED

Dry bottom pulverized coal, gas, and liquid fuel wall-fired boilers have used low-NOx burners to inject fuel and air from lower walls. Front-fired boilers have burners on one wall. Opposed-fired boilers have burners on front and back walls. These boilers typically use methods that reduce peak temperature, reduce residence time at peak temperature, or chemically reduce NOx (Methods 1, 2 & 3). These methods are used for large utility boilers in which combustion efficiency is all-important. NOx oxidation with absorption and removal of nitrogen (Methods 4 and 5) represent newer technologies that may be applied in the future. Using a sorbent (Method 6) is already in use for some boilers. See Table 6 for NOx technologies used for dry bottom wall-fired, front-fired or opposed-fired boilers.

Table 6: NOx technologies currently used for dry bottom wall-fired, front-fired or opposed-fired boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Low NOx Burners (LNB) Combustion Optimization Burners Out Of Service (BOOS) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR) Low NOx Burners (LNB)	35-90%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

DRY BOTTOM BOILERS - TANGENTIALLY FIRED

Dry bottom pulverized coal, gas, or liquid fuel tangentially-fired boilers use jets from each corner of a furnace to inject fuel and combustion air in a swirl. The injected mix of fuel and combustion air forms a fireball in the center of the boiler. This firing configuration is used in medium sized utility and large industrial boilers. This combustion technique holds flame temperatures down (Method 1). In addition, chemical reduction of NOx (Method 3) is frequently used. NOx oxidation (Method 4) techniques may be used in the future. Sorbents (Method 6) are already used for some boilers. See Table 7 for NOx technologies used for dry bottom tangentially fired boilers.

Table 7: NOx technologies currently used for dry bottom tangentially fired boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

WET BOTTOM (SLAG TAP) BOILERS

Wet bottom (slag tap) boilers use cyclone burners to create an intense flame. The flame is so hot that it melts ash, which then becomes slag that must be removed via a slag tap. These boilers are known to have higher NOx generation because combustion temperature is so high. As a result, this high temperature combustion technique is not widely used because the NOx concentration necessarily must be greater. Removal of non-fuel nitrogen as a reactant from the combustion process (Method 5) applies here. Reducing residence time at peak temperature, chemical

reduction of NOx, and NOx oxidation with absorption (Methods 2, 3 & 4) also apply to this combustion system. In addition, some slag tap boilers may be using sorbents (Method 6). There are recent reports that reducing peak temperature (Method 1) so that ash just melts has been used. See Table 8 for NOx technologies used for slag tap boilers.

Table 8: NOx technologies currently used for wet bottom (slag tap) boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	30-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	20-50%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Use Oxygen Instead Of Air Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

FLUIDIZED BED

Fluidized bed combustion occurs in a bed of crushed coal that has air flowing upward through it to make coal particles behave like a fluid. Boiler pipes can be either submerged in the bed or exposed to the hot gases after they leave the bed. The fluidized bed is temperature controlled (Method 1). The bed also is a chemically reducing region in which available oxygen is consumed by carbon (Method 3) that reduces ionization of nitrogen. Excess air is injected (Method 2) over the fluidized bed to complete combustion of CO and other burnables. This allows for the addition of pulverized limestone (Method 6) to coal in the fluidized bed. Sulfur oxides then react with the limestone to form gypsum, a marketable product. Gypsum must be separated from the ash. As a result, NOx generation can be essentially limited to prompt NOx and fuel NOx. See Table 9 for NOx technologies used for fluidized bed combustion units.

Table 9: NOx techniques currently used for fluidized bed combustion.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Reduced Air Preheat	No Data
2.Reducing residence time at peak temperature	Inject Steam	No Data
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction(SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

STOKERS WITH TRAVELING GRATE

Stokers with traveling grate cause the coal to move as it burns. Thus, char combustion is in one zone while volatiles are liberated and combusted in another zone. These stokers are commonly used with industrial boilers that are smaller than utility boilers. Reducing peak temperature, chemical reduction of NOx, and sorbents (Methods 1, 3 & 6) usually are applied. Perhaps NOx oxidation (Method 4) also will apply in the future. See Table 10 for NOx technologies used for stokers with traveling grates.

STOKERS WITH SPREADERS

Stokers with spreaders throw coal over the grate in a controlled manner. Coal is crushed, but particles are typically larger than pulverized coal. Therefore, combustion of volatiles begins while coal is in flight and combustion of char occurs on the grate. This system is used with somewhat larger boilers than stokers with traveling grates. It can be used in power plants, but this combustion system is used mainly for industrial boilers. Like stokers with traveling grates, reducing peak temperature, chemical reduction of NOx, and sorbents (Methods 1, 3, and 6) usually are applied. Perhaps NOx oxidation (Method 4) also will apply in the future. See Table 11 for NOx technologies used for stokers with Spreader grates.

Table 10: NOx technologies currently used for stokers with traveling grates.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Combustion Optimization Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	35-50%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	55-80%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

GAS TURBINES

Gas turbines use the Brayton Cycle with a burner to raise temperature of gas after compression and before expansion through the turbine. Turbines mainly use reducing peak temperature and reducing residence time (Methods 1 and 2) approaches to limit NOx emissions. Because addition of particles to air flow entering the turbine would accelerate erosion of turbine blades, sorbents (Method 6) could only be applied after the expansion in the turbine. NOx reduction (Method 3) has been used to treat exhaust gases. Many turbine operators claim that they use "good combustion practices" that do reduce the particles that produce visible emissions (which they equate with pollution), but say nothing about the NOx emissions which are not visible.

Cogeneration units use a gas turbine to generate electricity and provide preheated combustion air for a boiler. Gas turbine exhaust is typically 10-15% oxygen and can be used to provide combustion air for a low pressure boiler. That boiler can be used to provide steam for another turbine, a process heater, a space heater, or some combination of these. If a steam turbine is used to generate electricity, it may constrain what can be done. Sorbent particles can be introduced to a flow after it leaves a gas turbine in order to control NOx. There has also been some success in reducing NOx concentrations when burning biomass fuels in a boiler. See Table 12 for NOx technologies used for gas turbines.

Table 11: NOx technologies currently used for stokers with spreader grates.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Low NOx Burners (LNB) Combustion Optimization Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-65%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-65%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-80%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

INTERNAL COMBUSTION RECIPROCATING ENGINES

Internal combustion engines use air-to-fuel ratio and ignition/injection timing to control maximum temperature and residence time. This can reduce the concentration of NOx that is generated by reducing peak temperature (Method 1). Valve timing adjustments can reduce residence time at peak temperature (Method 2) to control NOx formation. Chemical reduction of NOx (Method 3) is used in catalytic converters to reduce NOx to N_2. Some stationary engines use both Method 3 and NOx oxidation (Method 4). A non-thermal plasma reactor was developed for treatment of diesel exhaust, but is not yet marketed to our knowledge. A plasma ignition system allows greater freedom in the air-fuel ratio and the ignition timing of spark ignition engines. See Table 13 for NOx technologies used for stationary internal combustion engines.

WHAT DOES NOx ABATEMENT AND CONTROL COST?

The cost of NOx abatement and control has been changing rapidly with dramatic reductions in recent years. Table 14 gives the 1993 cost as given in the Alternative Control Techniques

Table 12: NOx technologies currently used for gas turbines.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Natural Gas Reburning (NGR) Low NOx Burners (LNB) Inject Water or Steam Reduced Air Preheat Catalytic Combustion	70-85%
2.Reducing residence time at peak temperature	Air Staging of Combustion Inject Steam	70-80%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR) Low NOx Burners (LNB)	70-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	No Data
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Ducts	60-90%

Table 13: NOx technologies currently used for stationary internal combustion engines.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Air/fuel Ratio Timing of Ignition/Type of Ignition Pre-Stratified Combustion	20-97%
2.Reducing residence time at peak temperature	Valve Timing	No Data
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Non-Selective Catalytic Reduction (NCSR)	80-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	80-95%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Exhaust Ducts Adsorber in fixed Bed	60-90%

Table 14. 1993 Costs of NOx Controls

	Cost of NOx Controls in 1993 Dollars					
Control Device	Low -Cap. $/MMBTU	High -Cap. $/MMBTU	Low - Oper. $/MMBTU	High -Oper. $/MMBTU	Low $/ton	High $/ton
LNB	650	8,300	340	1,500	240	4,300
LNB + FGR					650	7,630
SNCR	1,600	3,300	680	1,200	N/A	N/A
(1994 ESTIMATE)					700	1,300
SCR	2,400	20,000	1,500	5,800	1,810	10,900
(1994 ESTIMATE)					500	2,800

Document NOx Emissions from Industrial/Commercial/Institutional Boilers (EPA 453/R-94-022).
The EPA Region III Low-NOx Control Technology Study in 1994 said that low-NOx burners had both beneficial effects on operating costs and detrimental effects on the burners, their life expectancy, and the boilers in which they were installed. Coal quality and some boiler designs caused NOx to remain high even after low-NOx burners were in place. Capital costs ranged from $1.91 to $54.24 per kW. Operating costs ranged from $-23,000 (a profit) to $1,113,750 per year. Thus, no reliable cost estimates could be obtained regarding low-NOx burner operation. Coal quality, boiler capacity, and burner design were among the variables influencing this cost. Many plants could not even give an estimate. SNCR cost between $700 and $1,300 per ton of NOx reduced. SCR cost between $500 and $2,800 per ton of NOx reduced.[25] However, cost per ton of NOx removed for all technologies is apparently becoming smaller.

These costs vary by control technique; type of fuel; grade of fuel; size of boiler, engine or turbine; type of boiler, or turbine; and other factors. Other costs were also changing with time. Therefore you need to examine the costs of these NOx control technologies for a specific application and at a particular time.

These preliminary cost estimates will also be further reduced as operating experience is gained, competition sharpens, and design iterations eliminate the high-maintenance or life-shortening features. Confidence in this view of the future is based upon reports that some users of low-NOx burners had already seen in 1994 that operating costs could be reduced to make the changeover yield a net profit. SCR and SNCR costs may also have declined further, since there is now competition for these technologies.

This analysis was supported by 1997 cost figures. These are presented in Table 15. This table is from the Analyzing Electric Power Generation Under the CAAA [26]. It appears that competition and improved designs are still driving the costs downward. The Table was presented in that publication and is presented here for your convenience.

Table 15. 1997 Costs of NOx Controls

Analyzing Electric Power Generation Under the CAAA -- Cost Estimates[26]					
Boiler Type	Control Type	Capital Cost	Fixed O & M	Variable O& M	% Control
		$/kW	$/kW/yr	mils/kWh	
Wall Fired	LNB w/o OFA	16.8	0.25	0.05	67.5
Wall Fired	LNB w/ OFA	22.8	0.35	0.07	67.5
Tang-Fired	LNB w/ OFA	32.3	0.49	0	47.3
Tang-Fired LNB w/ SOFA		34.7	0.53	0	52.3
Tang Fired LNB w/ BOFA		46.7	0.71	0.02	57.3
Cell Burners	Non Plug-In Comb. Ctl.	22.8	0.34	0.07	60
Cyclone	Coal Reburning	70.7	1.07	0.25	50
Wet Bottom	NOx Comb. Ctl.	9.6	0.14	0.05	50
Vert. Fired	NOx Comb. Ctl.	10.8	0.17	0.05	40
	SCR -Low NOx Rate	69.7	6.12	0.24	70
	SCR- High NOx Rate	71.8	6.38	0.4	80
	SNCR-Low NOx Rate	16.6	0.24	0.82	40
	SNCR-Cyclone	9.6	0.14	1.27	35
	SNCR-High NOx Rate	19	0.29	0.88	35
	Nat.Gas Reburn-Low	32.4	0.49		40
	Nat.Gas Reburn-High	32.4	0.49		50

Note that in Table 8 the following acronyms are used:

LNB is low-NOx burner
OFA is closed coupled overfire air
SOFA is separate over fire air
BOFA is both close coupled and over fire air
Comb. Ctl. is combined controls

The Institute of Clean Air Companies also suggests that in 1999 SCR will cost $50 - $80 per kW for retrofit to units, which relates to $400-$1800 per ton of NOx that is destroyed.[34] Their cost estimate for SNCR ranges from $5-$15 per kW, which relates to $400-$2000 per ton of NOx that is destroyed.[35] Cost-effectiveness does not correlate with boiler capacity alone - other variables such as type and quality of fuel, type of boiler, SNCR/SCR design, etc enter into the analysis.

While the "Performance of Selective Catalytic Reduction on Coal-fired Steam Generating Units" study was for Germany, it cited a recent cost range for SCR from $52 to $77 per kW with retrofit units tending to have lower costs. Thus, the costs in Germany were very similar to costs in the U.S.A., except that retrofit costs usually are greater in the United States.

Table 16, Unit Costs for NOx control Technologies for Non-Utility Stationary Sources, is from the report "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis." The report was prepared for EPA by the Pechan-Avanti Group. It indicates efficiencies and cost estimates for various NOx technologies for the year 2007. This appears to be a conservative estimate of efficiency and cost. Efficiencies indicated in the table tend to be lower than currently demonstrated efficiencies. Costs were based on historical information and, therefore, should be high estimates because NOx technology costs appear to be declining over time. The table was included here to indicate the relative efficiency and cost of NOx technologies for specific types of combustion systems.

The Alternative Control Techniques Document NOx Emissions from Stationary Reciprocating Internal Combustion Engines contains cost algorithms for the pollution prevention techniques and control technology applied to internal reciprocating engines. Costs for NOx elimination run from $250/ton to $1,300/ton for engines larger than 1,000 horsepower. For smaller engines the cost runs from $400/ton to over $3,500/ton.

ARE THESE METHODS SUFFICIENT?

YES, these methods are sufficient to meet the present goal of reducing NOx emissions 2 million tons below 1980 emissions.[47] The goal appears to be set at a level that can be achieved based on the state of NOx technology in 1996. However, we will have to see whether achieving our present goal provides the needed relief. A still more stringent set of standards may become necessary at sometime in the future.

As a high-technology nation and with a large urban and suburban population, we depend on automobiles, buses, airplanes, railroads, and trucks for transportation. We also depend upon electric power for computers, lights, air conditioning, and commerce. Therefore, we seem caught in a dilemma, for, while we depend on transportation, vehicles produce most of our NOx. While we also consume electric power as part of our market economy, electric power generation also generates over 40% of our NOx from stationary sources in 1995.[34]

We also need to generate less NOx without regard to the ionization level of the nitrogen. In 1999, we are currently not capable of doing that. Therefore, we must do the best that we can,

Table 16: Unit Costs for NO_x Control Technologies for Non-Utility Stationary Sources

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
ICI Boilers - Coal/Wall	SNCR	40	1,870	1,380
ICI Boilers - Coal/Wall	LNB	50	3,490	2,600
ICI Boilers - Coal/Wall	SCR	70	2,910	2,450
ICI Boilers - Coal/FBC	SNCR - Urea	75	1,220	910
ICI Boilers - Coal/Stoker	SNCR	40	1,810	1,350
ICI Boilers - Coal/Cyclone	SNCR	35	1,480	1,110
ICI Boilers - Coal/Cyclone	Coal Reburn	50	3,730	710
ICI Boilers - Coal/Cyclone	NGR	55	3,730	710
ICI Boilers - Coal/Cyclone	SCR	80	1,840	1,560
ICI Boilers - Residual Oil	LNB	50	940	1,020
ICI Boilers - Residual Oil	SNCR	50	5,600	1,950
ICI Boilers - Residual Oil	LNB + FGR	60	2,670	920
ICI Boilers - Residual Oil	SCR	80	3,460	1,840
ICI Boilers - Distillate Oil	LNB	50	2,810	4,950
ICI Boilers - Distillate Oil	SNCR	50	10,080	3,520
ICI Boilers - Distillate Oil	LNB + FGR	60	5,960	1,810
ICI Boilers - Distillate Oil	SCR	80	6,480	3,460
ICI Boilers - Natural Gas	LNB	50	1,950	1,560
ICI Boilers - Natural Gas	SNCR	50	8,400	2,930
ICI Boilers - Natural Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Natural Gas	OT + WI	65	1,620	760
ICI Boilers - Natural Gas	SCR	80	5,190	2,770
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	55	2,090	1,430
ICI Boilers - Wood/Bark/FBC	SNCR - Ammonia	55	1,660	1,210
ICI Boilers - MSW/Stoker	SNCR - Urea	55	2,610	1,830
ICI Boilers - Process Gas	LNB	50	1,950	1,560
ICI Boilers - Process Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Process Gas	OT + WI	65	1,620	760
ICI Boilers - Process Gas	SCR	80	4,990	2,570
ICI Boilers - Coke	SNCR	40	1,870	1,380
ICI Boilers - Coke	LNB	50	3,490	2,600
ICI Boilers - Coke	SCR	70	2,910	2,450
ICI Boilers - LPG	LNB	50	2,810	4,950
ICI Boilers - LPG	SNCR	50	10,000	3,440
ICI Boilers - LPG	LNB + FGR	60	5,960	1,810
ICI Boilers - LPG	SCR	80	6,240	3,220
ICI Boilers - Bagasse	SNCR - Urea	55	2,090	1,430
ICI Boilers - Liquid Waste	LNB	50	940	1,020
ICI Boilers - Liquid Waste	SNCR	50	5,560	1,910
ICI Boilers - Liquid Waste	LNB + FGR	60	2,670	920
ICI Boilers - Liquid Waste	SCR	80	3,320	1,710
Internal Combustion Engines - Oil	IR	25	1,840	1,160

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Internal Combustion Engines - Oil	SCR	80	4,690	1,850
Internal Combustion Engines - Gas	IR	20	2,430	1,320
Internal Combustion Engines - Gas	AF RATIO	20	3,730	900
Internal Combustion Engines - Gas	AF + IR	30	3,430	1,080
Internal Combustion Engines - Gas	L-E (Medium Speed)	87	890	N/A
Internal Combustion Engines - Gas	L-E (Low Speed)	87	4,000	1,500
Internal Combustion Engines - Gas	SCR	90	5,547	1,075
IC Engines - Gas, Diesel, LPG	IR	25	1,840	1,160
IC Engines - Gas, Diesel, LPG	SCR	80	4,690	1,850
Gas Turbines - Oil	Water Injection	68	3,080	1,540
Gas Turbines - Oil	SCR + Water Injection	90	4,240	1,860
Gas Turbines - Natural Gas	Water Injection	76	3,590	1,750
Gas Turbines - Natural Gas	Steam Injection	80	2,490	1,190
Gas Turbines - Natural Gas	LNB	84	1,170	240
Gas Turbines - Natural Gas	SCR + LNB	94	4,850	1,140
Gas Turbines - Natural Gas	SCR + Steam Injection	95	3,750	1,570
Gas Turbines - Natural Gas	SCR + Water Injection	95	5,040	2,060
Gas Turbines - Jet Fuel	Water Injection	68	3,080	1,540
Gas Turbines - Jet Fuel	SCR + Water Injection	90	4,240	1,860
Process Heaters - Distillate Oil	LNB	45	8,290	2,320
Process Heaters - Distillate Oil	LNB + FGR	48	10,130	4,000
Process Heaters - Distillate Oil	SNCR	60	6,210	3,230
Process Heaters - Distillate Oil	ULNB	74	5,110	1,450
Process Heaters - Distillate Oil	SCR	75	18,970	12,520
Process Heaters - Distillate Oil	LNB + SNCR	78	7,160	3,630
Process Heaters - Distillate Oil	LNB + SCR	92	18,770	10,910
Process Heaters - Residual Oil	LNB + FGR	34	8,330	3,290
Process Heaters - Residual Oil	LNB	37	6,010	1,690
Process Heaters - Residual Oil	SNCR	60	3,730	2,050
Process Heaters - Residual Oil	ULNB	73	3,080	860
Process Heaters - Residual Oil	LNB + SNCR	75	4,730	2,510
Process Heaters - Residual Oil	SCR	75	10,560	7,170
Process Heaters - Residual Oil	LNB + SCR	91	11,170	6,550
Process Heaters - Natural Gas	LNB	50	5,250	4,290
Process Heaters - Natural Gas	LNB + FGR	55	7,610	5,890
Process Heaters - Natural Gas	SNCR	60	5,560	3,740
Process Heaters - Natural Gas	ULNB	75	3,580	2,870
Process Heaters - Natural Gas	SCR	75	24,840	16,760
Process Heaters - Natural Gas	LNB + SNCR	80	6,960	5,080
Process Heaters - Natural Gas	LNB + SCR	88	23,880	16,500
Process Heaters - Process Gas	LNB	50	5,250	4,290
Process Heaters - Process Gas	LNB + FGR	55	7,610	5,890
Process Heaters - Process Gas	SNCR	60	5,560	3,740
Process Heaters - Process Gas	ULNB	75	3,580	2,870
Process Heaters - Process Gas	SCR	75	24,840	16,760
Process Heaters - Process Gas	LNB + SNCR	80	6,960	5,080
Process Heaters - Process Gas	LNB + SCR	88	23,880	16,500

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Process Heaters - LPG	LNB	45	8,290	2,320
Process Heaters - LPG	LNB + FGR	48	10,130	4,000
Process Heaters - LPG	SNCR	60	6,210	3,230
Process Heaters - LPG	ULNB	74	5,110	1,450
Process Heaters - LPG	SCR	75	18,970	12,520
Process Heaters - LPG	LNB + SNCR	78	7,160	3,630
Process Heaters - LPG	LNB + SCR	92	18,770	10,910
Process Heaters - Other Fuel	LNB + FGR	34	8,330	3,290
Process Heaters - Other Fuel	LNB	37	6,010	1,690
Process Heaters - Other Fuel	SNCR	60	3,730	2,050
Process Heaters - Other Fuel	ULNB	73	3,080	860
Process Heaters - Other Fuel	LNB + SNCR	75	4,730	2,510
Process Heaters - Other Fuel	SCR	75	10,560	7,170
Process Heaters - Other Fuel	LNB + SCR	91	11,170	6,550
Adipic Acid Manufacturing	Thermal Reduction	81	1,000	1,000
Adipic Acid Manufacturing	Extended Absorption	86	210	210
Nitric Acid Manufacturing	Extended Absorption	95	840	840
Nitric Acid Manufacturing	SCR	97	1,010	1,010
Nitric Acid Manufacturing	SNCR	98	940	940
Glass Manufacturing - Container	Electric Boost	10	17,050	17,050
Glass Manufacturing - Container	Cullet Preheat	25	2,240	2,240
Glass Manufacturing - Container	LNB	40	4,040	4,040
Glass Manufacturing - Container	SNCR	40	3,320	3,320
Glass Manufacturing - Container	SCR	75	4,550	4,550
Glass Manufacturing - Container	OXY-Firing	85	10,960	10,960
Glass Manufacturing - Flat	Electric Boost	10	5,540	5,540
Glass Manufacturing - Flat	LNB	40	1,660	1,660
Glass Manufacturing - Flat	SNCR	40	1,380	1,380
Glass Manufacturing - Flat	SCR	75	1,490	1,490
Glass Manufacturing - Flat	OXY-Firing	85	4,530	4,530
Glass Manufacturing - Pressed	Electric Boost	10	20,910	20,910
Glass Manufacturing - Pressed	Cullet Preheat	25	1,930	1,930
Glass Manufacturing - Pressed	LNB	40	3,570	3,570
Glass Manufacturing - Pressed	SNCR	40	3,080	3,080
Glass Manufacturing - Pressed	SCR	75	5,170	5,170
Glass Manufacturing - Pressed	OXY-Firing	85	9,310	9,310
Cement Manufacturing - Dry	Mid-Kiln Firing	30	1,110	1,110
Cement Manufacturing - Dry	LNB	30	1,340	1,340
Cement Manufacturing - Dry	SNCR - Urea Based	50	1,280	1,280
Cement Manufacturing - Dry	SNCR - NH3 Based	50	1,490	1,490
Cement Manufacturing - Dry	SCR	80	6,850	6,850
Cement Manufacturing - Wet	Mid-Kiln Firing	30	1,010	1,010
Cement Manufacturing - Wet	LNB	30	1,260	1,260
Cement Manufacturing - Wet	SCR	80	5,840	5,840
Iron & Steel Mills - Reheating	LEA	13	3,160	3,160
Iron & Steel Mills - Reheating	LNB	66	720	720
Iron & Steel Mills - Reheating	LNB + FGR	77	900	900

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Iron & Steel Mills - Annealing	LNB	50	1,350	1,350
Iron & Steel Mills - Annealing	LNB + FGR	60	1,790	1,790
Iron & Steel Mills - Annealing	SNCR	60	3,130	3,130
Iron & Steel Mills - Annealing	LNB + SNCR	80	3,460	3,460
Iron & Steel Mills - Annealing	SCR	85	8,490	8,490
Iron & Steel Mills - Annealing	LNB + SCR	90	9,070	9,070
Iron & Steel Mills - Galvanizing	LNB	50	1,170	1,170
Iron & Steel Mills - Galvanizing	LNB + FGR	60	1,370	1,370
Municipal Waste Combustors	SNCR	45	2,140	2,140
Medical Waste Incinerators	SNCR	45	8,570	8,570
Space Heaters - Distillate Oil	LNB	50	2,810	4,950
Space Heaters - Distillate Oil	SNCR	50	10,000	3,440
Space Heaters - Distillate Oil	LNB + FGR	60	5,960	1,810
Space Heaters - Distillate Oil	SCR	80	6,240	3,220
Space Heaters - Natural Gas	LNB	50	1,950	1,560
Space Heaters - Natural Gas	SNCR	50	8,330	2,860
Space Heaters - Natural Gas	LNB + FGR	60	6,110	1,420
Space Heaters - Natural Gas	OT + WI	65	1,620	760
Space Heaters - Natural Gas	SCR	80	4,990	2,570
Ammonia - NG-Fired Reformers	LNB	50	1,950	1,560
Ammonia - NG-Fired Reformers	SNCR	50	8,330	2,860
Ammonia - NG-Fired Reformers	LNB + FGR	60	6,110	1,420
Ammonia - NG-Fired Reformers	OT + WI	65	1,620	760
Ammonia - NG-Fired Reformers	SCR	80	4,990	2,570
Ammonia - Oil-Fired Reformers	LNB	50	940	1,020
Ammonia - Oil-Fired Reformers	SNCR	50	5,560	1,910
Ammonia - Oil-Fired Reformers	LNB + FGR	60	2,670	920
Ammonia - Oil-Fired Reformers	SCR	80	3,320	1,710
Lime Kilns	Mid-Kiln Firing	30	1,110	1,110
Lime Kilns	LNB	30	1,340	1,340
Lime Kilns	SNCR - Urea Based	50	1,280	1,280
Lime Kilns	SNCR - NH3 Based	50	1,490	1,490
Lime Kilns	SCR	80	6,850	6,850
Comm./Inst. Incinerators	SNCR	45	2,140	2,140
Indust. Incinerators	SNCR	45	2,140	2,140
Sulfate Pulping - Recovery Furnaces	LNB	50	1,950	1,560
Sulfate Pulping - Recovery Furnaces	SNCR	50	8,330	2,860
Sulfate Pulping - Recovery Furnaces	LNB + FGR	60	6,110	1,420
Sulfate Pulping - Recovery Furnaces	OT + WI	65	1,620	760
Sulfate Pulping - Recovery Furnaces	SCR	80	4,990	2,570
Ammonia Prod; Feedstock Desulfurization	LNB + FGR	60	6,110	1,420
Plastics Prod-Specific; (ABS) Resin	LNB + FGR	55	7,610	5,890
Starch Mfg; Combined Operations	LNB + FGR	55	7,610	5,890

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
By-Product Coke Mfg; Oven Underfiring	SNCR	60	3,130	3,130
Pri Cop Smel; Reverb Smelt Furn	LNB + FGR	60	1,790	1,790
Iron Prod; Blast Furn; Blast Htg Stoves	LNB + FGR	77	900	900
Steel Prod; Soaking Pits	LNB + FGR	60	1,790	1,790
Fuel Fired Equip; Process Htrs; Pro Gas	LNB + FGR	55	7,610	5,890
Sec Alum Prod; Smelting Furn/Reverb	LNB	50	1,350	1,350
Steel Foundries; Heat Treating Furn	LNB	50	1,350	1,350
Fuel Fired Equip; Furnaces; Natural Gas	LNB	50	1,350	1,350
Asphaltic Conc; Rotary Dryer; Conv Plant	LNB	50	5,250	4,290
Ceramic Clay Mfg; Drying	LNB	50	5,250	4,290
Coal Cleaning-Thrml Dryer; Fluidized Bed	LNB	50	3,490	2,600
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	LNB	40	4,040	4,040
Sand/Gravel; Dryer	LNB + FGR	55	7,610	5,890
Fluid Cat Cracking Units; Cracking Unit	LNB + FGR	55	7,610	5,890
Conv Coating of Prod; Acid Cleaning Bath	LNB	50	5,250	4,290
Natural Gas Prod; Compressors	SCR	20	5,547	1,075
In-Process; Bituminous Coal; Cement Kiln	SNCR - urea based	50	1,280	1,280
In-Process; Bituminous Coal; Lime Kiln	SNCR - urea based	50	1,280	1,280
In-Process Fuel Use;Bituminous Coal; Gen	SNCR	40	1,420	1,060
In-Process Fuel Use; Residual Oil; Gen	LNB	37	6,010	1,690
In-Process Fuel Use; Natural Gas; Gen	LNB	50	5,250	4,290
In-Proc;Process Gas;Coke Oven/Blast Furn	LNB + FGR	55	7,610	5,890
In-Process; Process Gas; Coke Oven Gas	LNB	50	5,250	4,290
Surf Coat Oper;Coating Oven Htr;Nat Gas	LNB	50	5,250	4,290
Solid Waste Disp;Gov;Other Incin;Sludge	SNCR	45	2,140	2,140

NOTE: *Small source cost per ton values are used to estimate control costs for all sources with 1995 NO_x emissions below 1 ton per day. If the ozone season daily 1995 baseline NO_x value is 1 ton or more, the cost per ton value for large sources is used.
N/A = not applicable. The population of medium speed gas-fired IC engines are all considered small.

and hope that we can endure while looking for the discovery and cost-reduction of the "better technology" that is capable of meeting the goal of sustainability. The reference literature suggests that the leading edge of pollution prevention and control technology in 1999 is capable of about 94%-99% control of NOx or 1 ppm-5 ppm of NOx.[27,28]

As we all know, the leading edge technology always costs more because engineering has not yet shifted from feasibility to cost-reduction, and competition in the technology is not fully developed. Therefore, we can expect technology to be more affordable with time and to also improve its capability. We should expect to see the goal change with time as the technology advances, and as the achievable goal becomes both more stringent and more economically feasible. At one time, the capabilities that we now have seemed beyond imagining, and the costs seemed prohibitive. We live in an interesting time when the NOx pollution prevention, abatement, and control technology is becoming more capable and more affordable.

CONCLUSIONS

1. Different fuels require different combustion, abatement and control techniques. Different coals have a varying content of volatile ingredients. The nitrogen content of fuel is important, as are the content of sulfur, lead, mercury and other contaminants. Ultra-low nitrogen content fuels have been developed and are already cost competitive. Thus, we can achieve some control of NOx from the lowered concentration of nitrogen in the fuel without investing in changed burner designs.[29]

2. The design of the boiler, internal combustion engine, or gas turbine has a major effect on the operation. NOx formation tends to increase with an increase in boiler capacity, because larger boilers tend to have more intense combustion with higher combustion temperatures and longer residence time for flue gases. The same appears to be true of engines and turbines.

3. Staging of the combustion is implicit in several pollution prevention techniques. Tandem application (or use of hybrid control technology) of NOx control techniques (first SNCR, then SCR in the duct, and then sorption before the ESP which is referred to as "polishing") have been used to achieve an overall reduction of 90+% in NOx and 80% in SOx, even without using low-NOx burners to lower NOx generation.

4. Combustion of natural gas and petroleum distillates can be controlled in much the same way as pulverized coal. The major differences between coal and natural gas or oil are that gas and oil: (1) generally are lower in sulfur and ash; (2) usually are lower in nitrogen; and (3) probably are lower in lead and mercury. Thus, gas and oil do not deactivate a catalyst used in Selective Catalytic Reduction (SCR) at the same rate that coal or semi-solid fuels do.

5. The semi-solid petroleum products can actually have higher levels of sulfur, nitrogen and other impurities than coal. They do not have as much char or ash as coal, but have more than the lighter distillates.

6. We should expect the declining cost trend of control technology to continue as operating experience is gained, firing techniques are adapted to fuels, design flaws are corrected, and new designs appear. We should expect to see costs become less as they are driven down by competition between suppliers of successful technologies.

7. NOx control technology appears capable of more than just meeting EPA's present goal and this should provide emission credits that can be traded to those firms that choose to continue emitting poorly controlled emissions. The sale of these credits by those that over-corrected for the present goal should further offset any net costs in adopting these control technologies.

8. Commercially available NOx control systems are already available. The availability of these technologies was part of the basis of the recent NOx SIP Call and Title IV regulations.

9. There has been an economic incentive to make combustion more efficient and to innovate ways to control nitrogen oxides. However, the amount of time and money that must be invested for a full-scale test of a strategy is significant. Acceptance requires that a technology be tried and succeed before a larger scale test is even contemplated. This delays acceptance of improved techniques.

10. There seems to be no control technology which is clearly superior for all combustion systems, boilers, engines, or fuels. Lacking a clear winner, one must select fuels and control technology either from among those already proven, or from a growing number of new and promising ideas.

11. The end of the search for control technologies is not yet in sight, and the search must continue. Past research must of necessity give ambivalent answers, because there are so many conflicting factors. However, at under $150 per ton of NOx prevented and with up to 80% control efficiency, the low-NOx burner, where applicable, appears to be among the least expensive emission control technologies. SCR is more expensive, but can obtain up to 94% control efficiency. SNCR can be adopted without the initial cost of catalyst, although it is somewhat less effective. LNB, SCR and SNCR are all viable technologies across a wide spectrum of applications.

12. Research and development will have to continue to seek more effective answers and try to balance them against cost and efficiency. The cost will decrease as technology advances, operating experience is gained, competition becomes sharper, design flaws are corrected, and better designs become available. Reliability can only be gained with time. Cost will be reduced with time and experience. We also must expect that the level of pollution prevention and control technology effectiveness will improve with time.

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TECHNICAL REPORT DATA

(Please read Instructions on reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-456/F-99-006R		

4. TITLE AND SUBTITLE	5. REPORT DATE
Nitrogen Oxides (NO_x) Why and How They Are Controlled	November 1999
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Clean Air Technology Center (MD-12) Information Transfer and Program Integration Division Office of Air Quality Planning and Standards U.S. Environmental Protection Agency Research Triangle Park, NC 27711	10. PROGRAM ELEMENT NO.
	11. CONTRACT/GRANT NO.
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Office of Air Quality Planning and Standards Research Triangle Park, NC 27711	13. TYPE OF REPORT AND PERIOD COVERED Final
	14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

For more information, call the CATC Information Line at (919) 541-0800 or access the CATC Web page at www.epa.gov/ttn/catc

16. ABSTRACT

The purpose of this document is to educate people about nitrogen oxides, how they are formed, the danger that they represent, and how emissions can be controlled. This knowledge is needed to make an informed choice of the control technology that is to be used.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
nitrous oxide, nitric oxide, nitrogen dioxide, dinitrogen pentoxide, nitrous acid, nitric acid, ozone, volatile organic compounds, VOC, generation, pollution prevention, control technology, control technologies, emission control, acid rain, combustion, boilers, gas turbines, internal combustion engines, cost of emission controls, air pollution	air pollution control technology, combustion, pollution prevention, nitrogen oxides, boilers, internal combustion engines, diesel engines	

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(Report)*	21. NO. OF PAGES
Release Unlimited, Available from the OAQPS TTN Web Page and NTIS	Unclassified	
	20. SECURITY CLASS *(Page)*	22. PRICE
	Unclassified	

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AFC Section 5.15, Water Resources
Replacement Pages 5.15-11 through 5.15-14

from irrigated agricultural and landscaping contributes to further losses from the system. Agricultural and landscaping irrigation is supplied from groundwater and, for the purposes of developing water budget estimates, the transpiration losses are included in the withdrawal quantities supplied by the groundwater system (minus return flow to the aquifer).

The impacts of spring discharge to the overall water balance is negligible due to the lack of surface water outflow from the basin and the fact that spring flow from former springs (Manse and Bennetts springs) has ceased mainly due to groundwater pumping resulting in declining groundwater levels throughout the basin (Cardno ENTRIX, 2011a).

The Pahrump Valley basin lies at higher elevations than adjacent groundwater basins, and groundwater moves from the upgradient Pahrump Valley into lower elevation basin through the groundwater system. This groundwater flow occurs mainly through the deeper carbonate aquifer (Cardno ENTRIX, 2011a). Subsurface discharge from the Pahrump Basin is approximately 12,000 ac-ft/yr.

Groundwater Recharge/Inflows

The primary sources of recharge to the groundwater basin are deep percolation of precipitation in the surrounding mountains, and deep percolation of applied water. Runoff associated with intense short-duration storms within the valley is sporadic and precipitation that is not consumed by vegetation does not contribute substantially to the recharge within the basin. Several studies on the recharge to the basin estimated an average value of 22,312 ac-ft/yr (Cardno ENTRIX, 2011a).

Groundwater Storage Changes

Groundwater level records within the California portion of the basin intermittently span a period from 1952 through 1984. In the southern part of the basin on the California side, records indicate that groundwater levels declined by nearly 60 feet at one well during the period from 1952 through 1975. Another well shows water levels declined by 0.6 foot from 1956 through 1972. Along the southeast margin of the basin, water levels declined in one well by approximately 2.3 feet (1959 through 1977) and by approximately 5.1 feet in a different well (1959 through 1984). Depth to water ranged from about 98 to 123 feet below ground surface. In the northern portion of the basin near Stewart Lake, water levels declined by about 2.7 feet at one location (1960 through 1976) and by about 2.1 feet at another location (1976 though 1984). Depth to water ranged between 20 to 40 feet below ground surface. Near Pahrump Lake in the central part of the basin, records show that water levels remained fairly unchanged from 1959 through 1976 at about 55 feet below ground surface (DWR, 2004).

Based on information related to regional groundwater levels analyzed by Cardno ENTRIX (2011a), the pre-development water level at the project site was approximately 100 to 200 feet below land surface. The water level onsite was measured at approximately 108 feet below land surface in the existing Orchard Well at the project site in 2011 (Cardno ENTRIX, 2011a). Water level changes in monitoring wells located in various parts of the Pahrump Valley are further described in the report. Declining water levels were recorded in all monitoring wells for the period of record with the exception of wells located at the eastern edge of the valley. The stability of groundwater levels on the eastern edge of the valley likely reflects the presence of recharge sources in the nearby Spring Mountains. Projections

of water level declines in the basin (Cardno ENTRIX, 2011a) show that the water levels at the California – Nevada border are projected to fall to levels deeper than 130 feet below ground surface by 2030. This projection corresponds to a water level decline of approximately 20 feet at the project site. However, the project site lies in a portion of the Pahrump Basin with moderately low water usage and may be separated from the main portion of the basin by a series of faults indicating that impacts from site pumping may be minimal in the surrounding area (Cardno ENTRIX, 2011a).

Additional information on historical basin pumpage is provided in Appendix 5.15D (Cardno ENTRIX, 2011a). The perennial basin yield of 19,000 ac-ft/yr is discussed in the attached report (based on U.S. Geological Surcey [USGS studies]). Beginning in the 1950s, basin perennial yields were exceeded and continued until the late 1980s. Pumpage then declined from the late 1970s to close to the basin yield, increased above the basin perennial yield through the 1980s, and has since declined to near the basin perennial yield in the 2000s due to reduced agricultural demand. However, as discussed previously, groundwater levels are still declining in the basin, and are projected to continue to decline in the future. Figure 5.15-4 shows recent (2006) groundwater levels in the basin.

Groundwater Quality

The overall quality of the groundwater in the Pahrump Basin is suitable for all beneficial uses. The character varies from calcium-magnesium bicarbonate to magnesium-calcium bicarbonate. TDS concentrations range between 145 to 540 milligrams per liter (mg/L) with an average concentration of about 340 mg/L. Fluoride content ranges from 0.1 to 0.8 mg/L, averaging about 0.4 mg/L. Boron content averages about 0.1 mg/L (DWR, 2004).

Groundwater samples were taken at the existing Orchard WCHCell on the HHSEGS site. Therefore, the analytical data represents the water quality anticipated at the project wells (see Table 5.14-4).

TABLE 5.15-4R
Groundwater Quality Data for Orchard Well at HHSEGS Site

	Units	Orchard Well
Alkalinity Bicarbonate (CaCO3)	mg/L	134
Alkalinity, Carbonate (CaCO3)	mg/L	<20
Alkalinity (Total)	mg/L	134
Aluminum	mg/L	<0.100
Arsenic (Total)	mg/L	<0.030
Barium (Total)	mg/L	0.028
Beryllium	mg/L	<0.003
Bicarbonate	mg/L	134
Cadmium	mg/L	<0.003
Calcium (Total)	mg/L	53
Chloride	mg/L	7.4
Chromium (Total)	mg/L	<0.005

TABLE 5.15-4R
Groundwater Quality Data for Orchard Well at HHSEGS Site

	Units	Orchard Well
Conductivity	μS/cm	557
Copper	mg/L	<0.005
Fluoride (Total)	mg/L	0.54
Hardness ($CaCO_3$)	mg/L	246
Iron (Total)	mg/L	<0.10
Lead	mg/L	<0.015
Magnesium	mg/L	27
Manganese	mg/L	<0.005
Nitrate/Nitrite	mg/L	7.3
pH	Std Units	8.0
Silica	mg/L	10
Silver	mg/L	<0.010
Sodium	mg/L	21
Sulfate	mg/L	110
Total Dissolved Solids (TDS)	mg/L	361
Total Organic Carbon (TOC)	mg/L	<1.0
Total Suspended Solids (TSS)	mg/L	<1.0
Zinc	mg/L	0.069

Source: Orchard Well Groundwater Sampling Laboratory Data

~~μg/L = micrograms per liter~~
mg/L = milligrams per liter
S/cm = microsiemens per centimeter
~~ND = None Detected~~
~~pCi/L = picocuries per liter~~

The beneficial uses of Pahrump Valley Groundwater Basin include municipal and domestic supply, agricultural supply, and freshwater replenishment (Lahontan RWQCB, 1995).

5.15.3.1.4 Flooding Potential

The project site is located in an area affected by two Federal Emergency Management Agency (FEMA) established Special Flood Hazard Zones. Both zones are classified as Zone A, which is defined as an area subject to a 1-percent annual chance of flooding with no base flood elevation determined. During major storm events, localized flooding may occur and ephemeral washes can overflow for a period of a few hours to up to a 24-hour period. Two unnamed dry lake beds exist downgradient to the project site that receive tributary watershed flows (VTN, 2011a). Flood zones are presently being re-analyzed by FEMA and are anticipated to be placed into effect by September 2011.

5.15.3.2 Stormwater Runoff and Drainage

5.15.3.2.1 Stormwater Runoff Prior to Construction

HHSEGS will be located on undeveloped land in the Pahrump Valley. Stormwater runoff at the site is predominantly sheet flow from west to east, eventually discharging into an unnamed dry lakebed northwest of the project site. Stormwater runoff also flows in the ephemeral washes located on the project site, draining from west to east, eventually discharging into the same dry lakebed located in Inyo County. Existing conditions are further described in Appendix 5.15C (VTN, 2011a).

Protection of soil resources during construction activities will be an important factor in the design of the erosion and sedimentation controls. To minimize wind and water erosion, open spaces will be preserved and left undisturbed maintaining existing vegetation (to the extent possible with respect to site topography and access requirements). Areas compacted during construction activities will be restored, as appropriate, to approximate preconstruction compaction levels to minimize the opportunity for any increase in surface runoff.

If needed, stone filters and check dams will be strategically placed throughout the project site to provide areas for sediment deposition and to promote the sheet flow of stormwater prior to leaving the project site boundary. Where available, native materials (rock and gravel) will be used for the construction of the stone filter and check dams. Diversion berms will be used to redirect stormwater around critical facilities, as required.

Periodic maintenance will be conducted as required after major storm events. Stone filters and check dams are not intended to alter drainage patterns but to minimize soil erosion and promote sheet flow.

5.15.3.2.2 Stormwater Runoff after Construction

Solar field development will maintain sheet flow where possible, with water exiting the site in existing natural contours and flows. The majority of the project site is expected to maintain the original grades and natural drainage features and, therefore, will require no added storm drainage control. In limited areas, such as the power blocks, switchyard, heliostat assembly buildings and administrative areas, the stormwater management system will include diversion channels, bypass channels, or swales to direct run-on flow from upslope areas and runoff flow through and around each facility. Diversion channels will be designed so that a minimum ground surface slope of 0.5 percent will be provided to allow positive, puddle-free drainage. To reduce erosion, storm drainage channels may be lined with a non-erodible material such as compacted rip-rap, geo-synthetic matting, or engineered vegetation. The design will be developed for sheet flow for all storm events less than or equal to a 100-year, 24-hour storm event.

All surface runoff during and after construction will be controlled in accordance with the requirements of the Drainage, Erosion, and Sedimentation Control Program (DESCP), and all other applicable LORS.

Paved access roads will be designed to allow stormwater to flow unimpeded across the roadways in order to maintain the existing sheet flow pattern. The perimeter road being constructed along the western property line will be built up within the middle two-thirds in order to act as a retention berm to contain increased flows from the postconstruction,