EXHIBIT C

Arizona Public Service's Response to Maricopa County's Request for Supplemental Information on Renewal of Permit V95007 (June 26, 2015)

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June 26, 2015

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SUBJECT: Response to Maricopa County request regarding the major modification and renewal of Permit V95007 for the Ocotillo Power Plant

Dear Mr. Sumner:

This letter provides responses to your letter dated April 29, 2015 requesting supplemental information for the major modification and renewal of Permit V95007 for the Ocotillo Power Plant. We have listed each of your requested items below and provided our response. In follow-up to this letter, APS intends to submit an updated permit application that includes updated Best Available Control Technology (BACT) analyses and updated air quality impact modeling analysis. Subsequent to your review of this response letter, APS requests a meeting with the Maricopa County Air Quality Department (MCAQD) and other agencies who may be involved with this permit application to discuss any outstanding issues.

The following paragraphs list the items for which you have requested additional information and our responses.

As described in the Ocotillo permit application, the purpose for the Ocotillo Modernization Project (the Project) is to provide peak electric capacity up to approximate 500 MW to replace the generation capacity that will be retired at Ocotillo plus additional peak generation capacity to handle future growth, and to provide quick ramping capability for grid stability and to backup renewable power and other distributed energy sources. This Project has already received a Certificate of Environmental Compatibility approved by the Arizona Corporation Commission (ACC) after a lengthy public comment period and hearing process.

APS continues to add renewable energy, especially solar energy, to the electric power grid to comply with the ACC mandated renewable energy standard and tariff (REST). However, because renewable energy is an intermittent source of electricity, a balanced resource mix is essential to maintain reliable electric service. As of January 1, 2015, APS has approximately 1,200 MW of renewable generation and an additional 46 MW in development. Within Maricopa County and the Phoenix metropolitan area, APS has about 115 MW of solar power and there is an additional 300 – 400 MW of rooftop photovoltaic (PV) solar systems. According to the Electric Power Research Institute (EPRI) study on the variability of solar power generation capacity, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, the total plant output for three large PV plants in Arizona have ramping events of up to 40% to 60% of the rated output power over one-minute to one-hour time intervals.[1] Considering only the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these types of solar systems would therefore be 165 to 310 MW per minute. The actual renewable energy load swings experienced on the APS system have shown rapid load changes from renewable energy sources of 25 to 300 MW in very short time periods, which is in agreement with the estimates found in the EPRI study.

To back-up the current and future renewable energy resources, the Project design requires quick start and power escalation capability to meet changing power demands and mitigate grid instability caused by the intermittency of renewable energy generation. To achieve these requirements, the project design is based on five GE LMS100 gas-fired simple cycle turbines, which have the capability to meet these design needs while complying with the proposed BACT air emission limits at loads ranging from 25% to 100% of the maximum output capability of the turbines. The proposed LMS100 CTGs can provide an electric power ramp rate equal to 50 MW per minute per CTG which is critical for the project to meet its purpose. When all five proposed CTGs are operating at 25% load, the entire project can provide approximately 375 MW of ramping capacity (i.e., from 125 to 500 MW) in less than two minutes.

1. BACT for GHG emissions from the gas turbines.

Before discussing the merits of the public comments received by Maricopa County that steam injection, dry low-NOx (DLN) combustors, combined cycle combustion turbines, batteries, or other energy storage options could either be used in addition to or in place of the proposed LMS100 CTGs, we would like to review the U.S. EPA's longstanding policy regarding BACT analyses and the scope of control technology options which the review agency may consider, especially as they relate to a proposed project's basic purpose or design.

In the EPA Environmental Appeals Board (EAB) decision on Prairie State Generating Station, PSD Appeal No. 05-05, the EAB explained (at pages 27-28) that the facility's "basic purpose" or basic design," as defined by the applicant, is the touchstone of EPA's policy on "redefining the source":

> … Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through the application of BACT. The parties' arguments, properly framed in light of their agreement on this central proposition, thus concern the proper

[1] Electric Power Research Institute (EPRI) report, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 3002001387, Technical Update, December 2013, conclusion, page 6-1.

> demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not.
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> We see no fundamental conflict in looking to a facility's basic "purpose" or to its "basic design" in determining the proper scope of BACT review, nor do we believe that either approach is at odds with past Board precedent.

This EAB decision was upheld by the 7th Circuit.[2]

When EPA issued guidance in 2011 specifically for greenhouse gas emissions, it confirmed that a BACT analysis should not redefine the source's purpose:[3]

> While Step 1 [of a BACT process] is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include lower pollution processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

The EAB has already analyzed the redefinition of the source concept in the context of a past permitting proceeding very similar to Ocotillo. In their challenges to a PSD permit issued for the Pio Pico Energy Center, the petitioners asserted before the EAB that EPA had erred in eliminating combined-cycle gas turbines in step 2 of its BACT analysis for greenhouse gases. Like Ocotillo, Pio Pico is a simple-cycle, gas-fired facility designed to back up renewable generation.

As the EAB recognized in its Pio Pico decision, consistent with EPA guidance, a permitting authority can consider peaking facilities, intermediate load facilities and base load facilities to be different electricity generation source types. The EAB explained how "plants operating in 'peaking mode' typically remain idle much of the time, but can be started up when power demand increases … and, unlike base load plants, typically use simple-cycle rather than combined-cycle units as well as smaller turbines."[4]

The EAB concluded that EPA did not define "source type" too narrowly in its BACT analysis for Pio Pico. The EAB also concluded that EPA's selection of a GHG BACT emission limit based on 50% load (which was not the most stringent emission rate in the record) was consistent with the definition of BACT, which affords EPA the discretion to set the emission limit at a level that ensures the facility can achieve consistent compliance over time. As the EAB explained, "permit writers retain discretion to set BACT levels that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis."[5] Further, the EAB determined that the

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[2] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

[3] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases at* 26 (Mar. 2011) (citing *Prairie State*, 13 E.A.D. at 23).

[4] *In re Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 63 (EAB Aug. 2, 2013).

[5] *Id.* at 78 (internal quotation marks omitted).

petitioners did not demonstrate that EPA failed to use its considered judgment when it incorporated safety factors, or compliance margins, into the GHG BACT emission limit.

EPA has addressed the issue of whether a peaking facility must consider incorporation of energy storage into a project in the BACT analysis. In EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[6] issued for a peaking facility to be comprised of reciprocating internal combustion engines ("RICE"), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." *Id.* at 1 (explaining that "'incorporating energy storage' in Step 1 of the BACT analysis for a [RICE] resource would constitute the consideration of an alternative means of power production in violation of long-established principles for what can occur in Step 1 of the BACT analysis") (citing *Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007)). EPA concluded that energy storage, either "to replace all or part of the proposed . . . project," would fundamentally redefine the source. *Id.* at 2.

Like the Project, the purpose of the Red Gate project was to provide reliable, rapidly dispatchable power to support renewables and the transmission grid. Because "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3. Similarly, in another PSD permit for a peaking facility, this time with natural gas-fired simple cycle units, EPA also concluded that energy storage would not meet the business purpose of the facility and therefore should not be considered in the BACT analysis.[7]

A. Please respond to the arguments that the Step 1 BACT analysis is incomplete because:

i. It fails to identify good combustion practices such as steam injection, dry low-NOx (DLN) combustors and steam injected gas turbines (STIG) that could be used on the same LMS100 model turbines as proposed for the project.

RESPONSE: The General Electric (GE) paper *New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™* cited by the commenter is a 2004 paper which preceded the first commercial operating date for an LMS100 CTG in June 2006.[8] GE has never built an LMS100 CTG with steam injection (either SAC or STIG variations) and does not currently offer the LMS100 with these

[6] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

[7] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

[8] Available at http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf.

designs.[9] Therefore, these technologies are not an "available control option" for the LMS100 CTGs and may be eliminated as a BACT option in Step 1 of the BACT analysis.

Dry Low NO_x (DLN) combustion is available for the LMS100 CTGs and under certain operating conditions can achieve the same NOx emission rate as water injection, equal to a CTG exhaust prior to the SCR systems of 25 ppmdv at 15% O_2. However, while water injected LMS100 CTGs can achieve the NO_x emission rate of 25 ppm continuously down to 25% of load, the DLN equipped units cannot achieve this NO_x emission rate at loads below 50% of load. Furthermore, the DLN equipped CTGs produce much more carbon monoxide (CO) and other products of incomplete combustion than the water injected CTGs. As a result, the DLN equipped CTGs can only meet the CO BACT emission limit down to 75% load, while the water injected CTGs can also achieve the CO BACT limit continuously down to 25% of load. Because a CTG turndown to 25% load is a major design criterion for the Project, utilizing DLN would require changing the basic purpose and design of the facility, and is therefore properly dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped CTGs makes the DLN equipped LMS100 CTGs technically infeasible for these peaking units. Therefore, even if DLN were retained in Step 1, DLN would be dismissed under Step 2 as technically infeasible.

DLN equipped LMS100 CTGs also have a lower peak electric generating capacity than the water injected units. The peak electric output at 105 ^{o}F is reduced significantly; from 109.9 MW (gross) for the water injected CTGs to only 97.2 MW for the DLN equipped CTGs. This is a significant reduction in peak generating and ramping capacity which directly affects the ability of the project to meet its basic design requirements, another reason for dismissal under Step 1 of BACT.

Since 2013, three peaking power plants consisting of 19 water-injected LMS100 simple cycle CTGs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). In 2013, a water-injected LMS100 CTG also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico. In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS100 simple cycle CTGs in 2013. The water-injected LMS100 CTGs have been selected for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS100 CTG is an available control option that is demonstrated, available and applicable, meeting the thresholds for Steps 1 and 2 of the BACT analysis.

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[9] E-mail from Phil Tinne, GE Power & Water, to Scott E McLellan, Arizona Public Service dated May 14, 2015, in which Mr. Tinne states " I confirm that we have not developed steam injection for the LMS100, either for NOx control or power supplementation, thus it is not on our option list."

ii. It fails to identify energy storage as an alternative to simple cycle gas turbines but with lower emissions.

RESPONSE: A commenter stated that there are several types of energy storage technologies available including batteries, compressed air energy storage (CAES), liquid air energy storage (LAES), pumped hydro, and flywheels. As explained above, incorporating energy storage into the project would fundamentally redefine the source. It would not meet the project purpose. Indeed, it is an alternative means of power production, the consideration of which "would stretch the term 'control technology' beyond the breaking point." *Sierra Club*, 499 F.3d at 655. Put simply, "energy storage cannot be required in the Step 1 BACT analysis as a matter of law."[10]

The use of energy storage was considered by APS in its planning process for the proposed Project. However, energy storage was not selected because it could not meet the basic needs and purpose. As with the Shady Hills and the Red Gate projects discussed above, the use of energy storage would not fulfill the site-specific purpose and need of the Project, which is to provide up to 500 MW of peak electric generating capacity for potentially extended periods of time at an existing plant site.

Even if there were an off-site generation source available for charging energy storage at the Ocotillo site, and even if it were appropriate to consider energy storage options in Step 1 of the BACT analysis, as explained further below, we are not aware of any available energy storage option that could supply a maximum power output of 500 MW for a potentially extended period of time, which is what this project requires. Therefore energy storage would also be eliminated at Step 2.

APS, in order to assure reliability must build a system that can meet not only a short peak demand, but also several short peak demands in a row, or an extended peak demand or even several extended peak demands. If the utility is reliant upon stored energy for some or all of its peaking power, be it battery, CAES, hydro pumping or other, at some point that stored energy may run out before it can be recharged, making the solution unreliable for meeting the full demand. Accordingly, energy storage is not compatible with the purpose and design of a true peaking facility such as Project to provide rapid, reliable power, which is why energy storage has been addressed and dismissed in most PSD permits for peaking facilities across the United States.

Battery Storage. The largest grid-connected battery storage systems that we are aware of include the 32 MW lithium-ion battery-based Laurel Mountain Wind Farm (W. Virginia) and the 36 MW lead-acid battery-based Notrees Battery Facility (Texas). The Laurel Mountain facility has 8.0 MWh of energy storage (and output); the Notree facility has 9.0 MWh of energy storage. The Project will be designed for a maximum energy output of approximately 500 MWh. The required electric energy output of the Project is therefore 50 times larger than the largest battery storage facilities currently in service.

The commenter has not presented any information showing that a battery storage facility, or any other energy storage facility at the proposed site, can provide the required maximum power capacity of 500 MW for multiple days, nor are we aware of such information. And the suggestion by the commenter

[10] Red Gate PSD Permit Response to Comments, at 1.

that a natural gas combined cycle unit combined with battery storage could reduce GHG emissions by 30% is not technically feasible, since there are no commercially demonstrated, available and applicable battery storage units on the scale of the proposed Project. Therefore, the battery storage option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project – to provide between 25 MW to 500 MW of electrical energy as needed[11] on an immediate basis, and potentially for an extended period of time, thereby redefining the source, and under Step 2 because it is not technically feasible at this time to produce up to 500 MW of electrical energy using this method, and may not even be technically feasible at much lower capacities.

Liquid air energy storage (LAES). Liquid air energy storage (LAES), also called cryogenic energy storage (CES), uses low temperature (cryogenic) liquids such as liquid air to store energy. This technology is being developed by Highview Power Storage in the United Kingdom. However, we are not aware of commercially operating LAES facilities in the World on the electric power output scale of the proposed Ocotillo Power Plant. Therefore, like batteries, the LAES option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project, which is to generate and provide to the grid 25 to 500 MW of electricity as needed.

It is important to note that contrary to the comments received, energy storage technologies are not "zero emissions" technologies. The "round trip" energy efficiency of LAES is expected to be 50 – 60%.[12] Therefore, while this technology may have near zero emissions at the site, the technology simply stores energy produced elsewhere. If that energy were produced for example at a natural gas-fired combined cycle facility with a GHG emission rate of 1,000 lb CO_2/MWh, the net emission rate after the LAES storage would be 1,670 to 2,000 lb CO_2/MWh. Thus, even if this technology were technically feasible, it may not have a lower GHG emission rate than the proposed project and would be dismissed in Step 4 as causing an unusual energy penalty and environmental impact.

Flywheel energy storage (FES). Flywheel energy storage (FES) uses electric energy input to spin a flywheel and store energy in the form of rotating kinetic energy. An electric motor-generator uses electric energy to accelerate the flywheel to speed. When needed, the energy is discharged by drawing down the kinetic energy using the same motor-generator. Because FES incurs limited wear even when used repeatedly, FES are best used for low energy applications that require many cycles such as for uninterruptible power supply (UPS) applications. Temporal Power, in collaboration with the Ministry of Energy and NRStor developed the first grid-connected flywheel energy storage

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[11] See the U.S. EPA's *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions PSD-TX-1322-GHG, page 7, available at http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-final-rtc.pdf. EPA states with respect to the use of batteries as a BACT control option, "Thus, the option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the project – to provide up 225MW of energy for necessary time periods – and it may also be eliminated at Step 2 of the BACT analysis because it does not meet the technical requirements of the project – to provide such power for multiple days."

[12] For example, the document *Liquid Air Energy Storage (LAES): Pilot Plant to Multi MW Demonstration Plant, Highview Power Storage*, LAES technology benefits include "60% efficiency in stand-alone mode. Integrates well with other industrial process plant (utilizing waste heat/cold) to enhance performance e.g. 70%+" Note that the Ocotillo Power Plant does not have waste heat/cold available to achieve the higher potential efficiency.

facility in Ontario, Canada. This is a 2 MW system primarily designed for short term energy balancing on the power grid. We are not aware of larger FES systems installed to date. Therefore, like batteries and LAES, the flywheel energy storage option has not been developed on a scale similar to the Project and may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project.

Compressed air energy storage (CAES). Compressed air energy storage (CAES) stores compressed air in suitable underground geologic structures when off-peak power is available, and the stored high-pressure air is returned to the surface to produce power when generation is needed during peak demand periods. There are two operating CAES plants in the world; a 110 MW plant in McIntosh, Alabama (1991) and a 290 MW plant in Huntorf, Germany (1978). Both plants store air underground in excavated salt caverns produced by solution mining. Other geological structures such as basalt flows may also be feasible CAES geologic formations. However, the Ocotillo Power Plant does not have any suitable geological structures in the vicinity of the plant. Like the other energy storage options, the CAES option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project, and it can also be eliminated at Step 2 of the BACT analysis as technically infeasible.

Pumped hydroelectric storage. Pumped hydroelectric storage projects move water between two reservoirs located at different elevations to store energy and generate electricity. When electricity demand is low, excess electric generating capacity is used to pump water from a lower reservoir to an upper reservoir. When electricity demand is high, the stored water is released from the upper reservoir to the lower reservoir through a turbine to generate electricity. Pumped storage projects have relatively high round trip efficiencies of 70 to 80%. However, there are no available water reservoirs at or near the Ocotillo Power Plant, and water resources in the Phoenix area are scarce. Therefore, this technology is not an "available control option" at the Ocotillo Power Plant and may be eliminated as a BACT option in Step 1 of the BACT analysis. And even if this option could be considered under Step 1, it can also be eliminated at Step 2 of the BACT analysis as technically infeasible.

iii. It fails to identify smaller units that could operate at 100% efficiency rather than 102 MW turbines operated at 25% load.

RESPONSE: A commenter suggests that the project should use smaller turbines or a combination of smaller and larger turbines, or even a combination of smaller turbines, larger turbines, and some form of four possible energy storage options. However, the commenter has not provided any specific project designs which could meet the purpose and needs of the project and would actually reduce CO_2 emissions as compared to the proposed Project. Therefore, a detailed response that considers the myriad of permutations of possible turbines that might be used is not warranted.[13] Moreover, the

[13] *See In re City of Palmdale*, PSD Appeal No. 11-07, slip op. at 47 (EAB Sept. 17, 2012) (noting that requiring a permitting authority to "analyze a myriad of potential [plant] configurations … would impose a heavy burden on the [permitting authority] that goes well beyond the permitting authority's obligations to consider and respond to public

EAB has concluded that relevant EPA guidance indicates that, in a BACT analysis, a permitting authority is only required to identify "general *types or categories* of control technologies" in Step 1, which it then ranks in Step 3. The guidance does "not suggest that the analysis should also identify and rank specific equipment *models* that are available for each type of technology considered."[14] (See also, Prairie State Generating Company, PSD Appeal No. 05-05 "It is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit.")

In any case, APS did consider the use of smaller turbines in the initial planning stages of the Project. But at the outset, it should be noted that as stated in the permit application, APS is proposing to install the most efficient simple cycle combustion turbines commercially available today. The use of an intercooler combined with higher combustor firing temperatures allows the LMS100 to achieve a simple cycle thermal efficiency of approximately 44% at 100% load operation. The LMS100 is the first production gas turbine in the power generation industry to employ this technology. The result is that the LMS100 GTs are among the most efficient, and therefore the lowest CO_2 emitting simple cycle gas turbines which are commercially available at this time.[15] It is contradictory for the commenter to argue that APS should be required to utilize the most efficient energy processes and technology possible, yet also argue that APS should instead install smaller, less efficient combustion turbines.

Furthermore, it is not possible to design or operate the power plant in a manner that would allow smaller CTGs to operate at 100% load at all times or even for the majority of the time and still meet the basic Project requirements. As we have noted in the permit application, the increase in renewable energy sources such as wind and solar on the electric grid and the intermittent nature of these sources is placing increased demands on grid stability. The new units need the ability to start quickly, change load quickly, and idle at low load, as well as be able to provide up to approximately 500 MW in total. This capability is not only very important for normal grid stability, but also absolutely necessary to integrate with and fully realize the benefits of distributed energy, such as, solar power and other renewable resources.

The Project requires quick starting, fast ramping units which can stabilize the grid over a range of 25 to 500 MW to allow for this increased renewable energy profile. Therefore, the commenter is incorrect that "A 25 MW turbine, for example, could be operated at 100% load, rather than operating a 102 MW unit at 25% load."[16] This operating scenario would not provide the fast ramp rate that the Project design requires. The LMS100 design can achieve a ramp rate of 50 MW per minute required for the project, over the range of 25 MW to 100 MW, but if smaller turbines were utilized it would

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comments and to satisfy statutory and regulatory obligations in setting a BACT emissions limit that protects public health and the environment.").

[14] *In re La Paloma Energy Center*, PSD Appeal No. 13-16, slip op. at 16 (EAB Mar. 14, 2014).

[15] In the press release for the California CPV Sentinel Energy Project, May 16, 2013, available at http://geenergyfinancialservices.com/press_releases/view/393 GE states "GE's LMS100® aeroderivative gas turbine, which uses advanced intercooling technology, is the world's most efficient simple–cycle gas turbine."

[16] Commenter's proposal would appear also redefine the source to be a base-load facility running at 100%.

require starting additional units which would require 10 minutes or more to achieve another 25 MW of electric output. This is not adequate to meet the grid stability requirements.

To meet the Project requirements, the use of smaller turbines would mean that additional numbers of less efficient turbines would need to be operated simultaneously at low loads and electric power ramp rate capable for the proposed LMS100 CTGs of 50 MW per minute per CTG. For example, if the Project were designed to use 50 MW turbines, two less efficient 50 MW turbines would need to be operated at low loads and ramp rate for one LMS100 CTG. Replacing a more efficient turbine with a less efficient turbine would actually *reduce* plant efficiency and *increase* GHG emissions for the plant.

B. Please respond to the arguments that the Step 2 BACT analysis is flawed because:

i. It fails to properly consider highly efficient combined cycle plants that achieve their efficiency at full and partial load as well as a wide range of ramp rates that respond to fluctuations in demand.

RESPONSE: The Project is being proposed to provide quick start and power escalation capability over the range of 25 MW to 500 MW to meet changing and peak power demands and mitigate grid instability caused by the intermittency of renewable energy generation. Electric utilities primarily use simple-cycle combustion turbines as peaking units, while combined cycle combustion turbines are installed to provide baseload capacity. The proposed LMS100 CTGs can provide an electric power ramp rate equal to 50 MW per minute per CTG which is critical for the project to meet its purpose. When all five proposed CTGs are operating at 25% load, the entire project can provide approximately 375 MW of capacity (i.e., from 125 to 500 MW) in less than two minutes. And while fast-start combined cycle units are available for some applications, the commenter has not shown that any of the combined cycle units can provide this very fast response time over a range of 25 MW to 500 MW, which is a design requirement of *this* Project. Nor are we aware of any.

Baseload and combined cycle units are unable to respond rapidly to the large swings in generation which can be caused by a sudden drop in generation from renewable energy sources. As stated in the BACT analysis (page 38 of the permit application) "The long startup time for combined cycle units is incompatible with the purpose of the Project which is to provide quick response to changes in the supply and demand of electricity in which these turbines may be required to startup and shutdown multiple times per day. Therefore, the use of combined cycle GTs is technically infeasible for the Project." This conclusion is consistent with the U.S. EPA Region 9 evaluation and conclusion regarding the technical feasibility of combined cycle units for the Pio Pico Energy Center.[17] This conclusion is also consistent with the U.S. EPA Region 4 conclusion regarding the use of combined cycle units at the EFS Shady Hills Project in which EPA stated, "Based on the short startup and

[17] See *Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center*, U.S. EPA, November 2012, and also the *Fact Sheet and Ambient Air Quality Impact Report For a Clean Air Act Prevention of Significant Deterioration Permit, Pio Pico Energy Center*, PSD Permit Number SD 11-01, June 2012, pages 16 – 17.

shutdown periods the simple cycle combustion turbines (SCCTs) offer, along with the purpose of the Project, CCCTs were considered a redefinition of the source and therefore, not considered in the BACT analysis."[18]

Combined cycle CTGs have other technical problems that also make them technically infeasible for this project. When a fast start, combined cycle CTG is started from a full stop as is typical for a peaking unit, the CTG is simply operating in the simple cycle mode. The large frame CTGs typically used in combined cycle applications do not have the high turndown ratio that can be achieved with aero-derivative CTGs like the LMS100. Large frame CTGs also have longer startup times. And because the LMS100 CTGs have an intercooler which is not used in large frame CTGs, the large frame CTGs are not as efficient when operated in simple cycle mode. Therefore, constructing a combined cycle unit and then operating the combined cycle unit as a peaking unit would mean that the combined cycle unit would operate primarily in the simple cycle mode and would result in more GHG emissions than properly constructing the plant using the proposed simple cycle CTGs.

Even a combined cycle CTG equipped with a fast start package is only capable of achieving startup within 30 minutes if the unit is already hot. If the unit is not hot, the combined cycle CTG may require up to 3½ hours to achieve full load under some conditions. These longer startup times are incompatible with the purpose of the proposed project to provide a rapid response to changes in the supply and demand of electricity. To keep the heat recovery steam generator (HRSG) and the steam turbine at a sufficiently high temperature to allow for quick startup of the CT, the facility would either have to operate continuously (and therefore it would no longer be a peaking facility) or it would have to operate an auxiliary boiler. The auxiliary boiler would need to be operated even when the peaking unit is not in service to keep the unit in hot standby, resulting in additional emissions of GHGs and other pollutants. Continuous operation of an auxiliary boiler at a peaking facility would be inconsistent with the needs of a peak electric generating facility.

For the above reasons, combined cycle CTGs are not feasible for the proposed Project and may therefore be rejected in Step 1 because, consistent with EPA's statements in the EFS Shady Hills Project, combined cycle CTGs would not meet the basic purpose and need of the Project and would therefore constitute a redefinition of the source. Combined cycle CTGs may also be rejected in Step 2 of the BACT analysis because they cannot meet the fast startup and ramp rates required for the Project and are technically infeasible options.

ii. The operation of the turbines as proposed seems to be at greater frequency and for longer hours than is ordinarily the case for peaker plants and thereby justifies the operation of combined cycle units in lieu of simple cycle units.

RESPONSE: The commenter stated that "The proposed operating mode is not consistent with peaking operation, and therefore the assumption that combined-cycle units are not appropriate is unsupported. The record shows that the Applicant intends to operate the facility much more frequently and for longer hours than a traditional 'peaking' unit."

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[18] EPA's EFS Shady Hills LLC Project (PSD-EPA-R4013) – Response to Comments, at 5.

The commenter also states "The assumed number of hours of operation can be back calculated from the emissions by dividing the tons per year per turbine by the pounds per hour per turbine. This calculation for the major pollutants yields an average of 3,571 hr/yr of normal operation per turbine. In addition, each turbine would undergo up to 730 startups/shutdowns per year, each lasting a total of 41 minutes (30 min startup, 11 min shutdown). This amounts to 499 hours per year per turbine of startup and shutdown. Thus, each turbine is permitted to operate 4,070 hr/yr or 46% of the time."

The operational limit in the draft permit, condition 19.b. of 18,800,000 mmBtu per year for all five turbines combined <u>includes all periods of operation, including periods of startup and shutdown</u>. At a maximum design heat input for each CTG of 970 mmBtu per hour, this limit is equal to 3,876 hours per year of operation. This operational limit is the basis for calculating the potential to emit for these CTGs and the entire Ocotillo Power Plant. However, this limit does not necessarily reflect the expected operation of the CTGs.

The operational limit in the draft permit equal to 3,876 hr/yr for each CTG is consistent with the following recently issued U.S. EPA PSD GHG permits for simple cycle CTG or RICE engine peaking plants.

Recent U.S. EPA PSD GHG permit operational limits for peak electric generating units.

Plant	U.S. EPA Permit No.	Operating Limit, 12-month Average	Equivalent Limit per Unit Hours per Year
Pio Pico Energy Center	SD 11-01	3,914,556 MMBtu	4,335
EFS Shady Hills	PSD-EPA-R4013	3,390 hr/yr per CT	3,390
Red Gate Power Plant	PSD-TX-1322-GHG	67,771 hr/yr, 12 engines	5,648

With respect to operating limits, the commenter also states that "more than 90% of existing simple-cycle units operated at 2,000 hours or less…, thus showing that operation greater than 2,000 hours is not consistent with the normal operation of combustion turbines in peaking service." Once again, the operational limit in the draft permit which is equal to 3,876 hr/yr of full load operation for each CTG is the basis for calculating potential emissions from the Project, but it does NOT reflect the expected typical operation, but rather worst-case operation. Combined cycle and other baseload electric generating units are typically permitted based on 8,760 hours per year of operation at their maximum rated capacity as the basis for the *potential* emissions from the facility. Yet a baseload unit may not actually operate at, or even close to, this maximum worse-case operating level.

The data presented by the commenter does not mean that a peaking unit may *never* need to operate for more than 2,000 hours per year. If a peaking unit operates more frequently in a particular year than is "typical" because of higher than average demand, it does not cease to be a peaking unit. As EPA stated in its response to comments for the EFS Shady Hills LLC Project, "If EPA were to restrict operation of the Shady Hills units to the 'typical' number of hours that a peaking unit is used, EPA would impair Shady Hills' ability to provide reliable peaking duty service during years in which circumstances requiring peak duty service occur more frequently than usual."[19] These circumstances could be due to local or regional electric generation or transmission problems, or it may be due to extreme weather conditions.

Thus, the operating limit for the Project should be consistent with other recent GHG limits for similar facilities, and it should be set so that it does not impair the ability of the Project to provide reliable peaking service during years in which circumstances may require more frequent operation. The draft limit equal to 18,800,000 mmBtu per year for all five turbines combined, including periods of startup and shutdown, is consistent with other permits and will allow sufficient operating flexibility to ensure the project can meet its purpose and need.

1. There are combined cycle turbines that are technically feasible to meet the projects generation purposes.

RESPONSE: As detailed above, combined cycle CTGs cannot provide the fast start and fast power ramp rates over the wide range of 25 MW to 500 MW that are required for this project. Therefore, for the same reasons that the U.S. EPA has rejected combined cycle CTGs for similar peak electric generating facilities, combined cycle units are not a technically feasible BACT option for the Project.

2. The ability of combined-cycle units to act as peaking units has been recognized on a number of occasions at other plants.

RESPONSE: The commenter states that "Combined-cycle units can act as peakers or load-following units by ramping up their combustion turbines very quickly, while still meeting full load simply by warming up the heat recovery steam generator in anticipation of increased demand. This point is important because the 'peak' is rarely a surprise."

Again, combined cycle CTGs cannot provide the fast start and very fast power ramp rates that are required for this project. Further, the need for the very fast power ramp rates for this Project is precisely because the growth in intermittent renewable energy resources on the grid - and which can come on and offline very rapidly - is making the ability to anticipate peak power or large grid power supply swings much more difficult. As noted previously, APS has approximately 1,200 MW of renewable generation and an additional 46 MW in development as of 1/1/2015. Within Maricopa County and the Phoenix metropolitan area, APS has about 115 MW of solar and an additional 300 – 400 MW of rooftop solar systems. According to an EPRI report[20], the total plant output for three large PV plants in Arizona have infrequent ramping events of 40% to 60% of the rated output for 1-minute, 10-minute, and 1-hour time intervals. Considering only the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these solar systems would be 165 to 310 MW per minute. The commenter also states that "It is factually inaccurate to

[19] See EPA's EFS Shady Hills LLC Project (PSD-EPA-R4013) – Response to Comments, page 8.
[20] Electric Power Research Institute (EPRI) report, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 3002001387, Technical Update, December 2013, conclusion, page 6-1.

claim that combined-cycle units are incapable of meeting the technical function of a load-following unit." That may be true, but it is irrelevant here. APS has not stated that "combined-cycle units are incapable of meeting the technical function of a load-following unit." APS is not proposing "load-following" units at all: APS is proposing peaking units, which have a ramp rate fast enough to replace intermittent renewable resources on a moment's notice. While combined-cycle units may load-follow in certain circumstances, they do not have the ramp rate necessary to fulfill this Project's purposes. For example, the commenter points to the Huntington Beach Energy Plant (HBEP) "peaking project" as an example of a combined cycle plant that can provide peak power. However, the HBEP is a 939 MW power plant which is almost twice the size of the proposed Project (and which is not yet operational). HBEP will consist of two power blocks each with a three-on-one configuration, i.e., each power block will have three Mitsubishi turbines, three heat recovery steam generators, and one steam turbine. As the commenter indicates, the HBEP has a maximum power island ramp rate of 110 MW/minute, or 220 MW for the entire project. For the Project, when all five proposed CTGs are operating at 25% load, the entire project can provide approximately 375 MW of ramping capacity (i.e., from 125 to 500 MW) in less than two minutes. The ramp rate capacity of the HBEP would not meet the Project needs.

C. Please respond to the arguments that the Step 5 BACT analysis is flawed because:

i. It is improper to set the GHG limit based upon emissions when operating at 25% of load because operation at that load level is unnecessary considering the alternative technologies available and BACT should have to be met at all operational load levels.

RESPONSE: The commenter has stated that "The assumption made by both the Applicant and the County that the GHG BACT limit must be set at the "worst case" scenario to allow the Ocotillo plant to operate at 25% load is improper. As discussed elsewhere, operation at 25% of the LMS100 design load, or about 25 MW, could be achieved by either using hybrid battery or other storage options, or smaller gas turbines, (e.g. 25-MW gas turbines) operated more efficiently at 100% load."

Our responses above have demonstrated that:

1. Battery and other energy storage options are not a technically feasible option for the Project and would redefine the project,
2. Combined cycle CTGs cannot meet the purpose and need for the Project, and
3. Smaller gas turbines, on the order of 25MW capacity, would not meet the Project requirements because they cannot supply the required power ramp rates for the Project.

As noted in the GHG Control Technology Review (page 48), EPA Region 9 provided a framework for addressing the variation of turbine efficiency and resulting GHG emission rate as a function of load in its "Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center," November 2012. EPA stated that it is not possible to predict the extent of part load operation during every year for the life of the generating facility, and that facilities are designed to meet a range of operating levels. Therefore, EPA explained it is inappropriate to establish a GHG permit limit that prevents the facility from generating electricity as intended. For the Pio Pico PSD permit, EPA determined that the appropriate methodology for setting the GHG BACT emission limit was to set the final BACT limit at a level achievable during the lowest load, "worst-case" normal operating conditions. (This same methodology has been used to develop the proposed GHG BACT limit for the Project which is based on 25% load operation.) And EPA did this even though the final limit was NOT the lowest emission rate in the record.

The Sierra Club challenged the Pio Pico Permit, stating that the Permit's GHG BACT emission limit is based on the "worst-case operating conditions" and conflicts both with the definition of BACT and EPA precedent. That challenge was reviewed by the U.S. Environmental Appeals Board (EAB). In summary, the EAB upheld the Region's decision, noting that BACT is achieved in the same manner at 50% load as it is at 75% and 100% load (and any other load level), even though the actual GHG emissions resulting from application of BACT may vary at different loads. The EAB also stated:

> Sierra Club's assertions regarding the "BACT-level emission limit" do not account for Pio Pico's operation as a peaking facility, which anticipates operation at various loads as part of the facility's inherent design and purpose. In addition, any assumption that a "BACT-level emission limit" only occurs at 100 percent load ignores the Board's extensive prior precedent set forth at the beginning of this section, which states that a BACT emission limit need not be the most stringent emission limit.

The framework established by EPA Region 9 is consistent with the U.S. EPA Office of Air and Radiation's document *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA document EPA-457/B-11-001, March 2011.[21] This document explains the requirements of EPA regulations, describes EPA policies, and recommends procedures for permitting authorities to use to ensure that GHG permitting decisions are consistent with applicable regulations. On page 44, EPA states:

> In setting the BACT limit in Step 5, the permitting authority should look at the range of performance identified previously and determine a specific limit to include in the final permit. In determining the appropriate limit, the permitting authority can consider a range of factors, including the ability of the control option to consistently achieve a certain emissions rate, available data on past performance of the selected technology, and special circumstances at the specific source under review which might affect the range of performance. In setting BACT limits, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue, and thus may

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[21] Available at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

consider safety factors unique to those circumstances in setting the limits.

APS has demonstrated that other technologies and options, including energy storage options, smaller turbines, and combined cycle turbines do not meet the project requirements. And contrary to the commenter's statements, operation at 25% of load is indeed part of the normal operation of these units, and is in fact an important design concept for these LMS100 CTG and for the planned Project. Because the BACT emission limit must be achievable across all load ranges for which these turbines are designed to operate, and because the Ocotillo CTGs are designed to operate continuously at loads as low as 25% of the maximum load, APS has proposed a CO_2 emission rate of 1,690 lb CO_2/MWh of gross electric output, based on a 12-month average. This limit is based on the annual average performance of the CTGs at 25% load at different ambient temperatures that would be expected throughout the year. This limit also includes a 6% safety factor for turbine variability and irreversible performance loss. The use of this safety factor is the same as that used by the U.S. EPA Region 9 for the Pio Pico Energy Center GHG emission limit, and which was also upheld by the EAB. Moreover, it is important to note that APS proposes that this limit includes ALL periods of operation, including periods of startup and shutdown.

The development of this limit is consistent with the framework developed by EPA Region 9 for addressing the variation of turbine efficiency and resulting GHG emission rate as a function of load, and it is also consistent with the U.S. EPA's *PSD and Title V Permitting Guidance For Greenhouse Gases*. While the proposed limit does not reflect the lowest GHG emission rate for similar simple cycle CTGs when operated constantly at maximum output, the limit does reflect the expected performance of these units at their lowest normal operating condition load, . As EPA stated, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue.

Based on the guidance provided by EPA and upheld by the EAB, the proposed CO_2 emission limit of 1,690 lb/MWh of gross electric output is appropriate and represents BACT for the control of GHG emissions from the proposed CTGs.

The commenter also noted that the permit application, Appendix B, page 25 states "neither DLN combustors nor water injection can operate at loads below approximately 50% of the maximum rated load." We would like to correct our previous statement. DLN combustion cannot operate and achieve the NOx emission rate of 25 ppmdv at 15% O_2 at loads below 50% of the rated load. However, as shown in the application, Appendix B, Table B6-7, and as stated in the GHG BACT analysis, water-injected LMS100 CTGs can achieve the CTG outlet NOx emission rate of 25 ppmdv at 15% O_2 and also the controlled NOx emission rate after the SCR systems of 2.5 ppmdv at 15% O_2 down to 25% of load. That is what APS has proposed. Accordingly, the pollutant emission limit set in the proposed permit is accurate and achievable by the proposed control option meeting the requirements of Step 5.

ii. It is based on an improperly long averaging time.

RESPONSE: The commenter has stated that the proposed BACT limit of 1,690 lb CO_2/MWh, based on a 12-month rolling average, is an improperly long averaging period. However, as stated in the BACT analysis, page 48, a 12-month rolling average basis is consistent with the majority of the CO_2 BACT emission limits, and is also consistent with the proposed CO_2 emission standard under 40 CFR 60 Subpart KKKK. In the preamble to the proposed rule, EPA stated "This 12-operating-month period is important due the inherent variability in power plant GHG emissions rates." EPA went on to say "a 12-operating month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities."

The final GHG BACT emission limits for the EFS Shady Hills Project (Florida), and the Red Gate Power Plant (Texas) are based on a 12-month rolling average. EPA Region 9 also noted in the Pio Pico response to comments that "EPA believes that annual averaging periods are appropriate for GHG limits in PSD permits because climate change occurs over a period of decades or longer, and because such averaging periods allow facilities some degree of flexibility while still being practically enforceable."

The proposed BACT limit of 1,690 lb CO_2/MWh, based on a 12-month rolling average was developed using the same framework and method as that used by the U.S. EPA Region 9 for the Pio Pico Energy Center. This methodology was upheld by the EAB and properly represents BACT for the control of CO_2 emissions from these proposed CTGs.

iii. The limit excludes GHGs during startup and shutdown. (Note: Recent GHG BACT permits contain startup and shutdown emissions for GHGs separate from the BACT output based limits that apply at all other times. Please propose and justify a GHG startup and shutdown emission limit.)

RESPONSE: In its application, APS had proposed a GHG emission rate of 1,690 lb CO_2/MWh of gross electric output, based on a 12-month rolling average which includes ALL periods of operation, including periods of startup and shutdown. To the extent the GHG BACT limit listed in Table 4 of the Draft Permit does not make that clear, it appears to be an oversight. We suggest that a footnote be added to Table 4 to clarify that for GHG, the BACT limit applies to all periods of operation. In its revised application, APS requests that the emission limit clearly state that the BACT emission limit of 1,690 lb CO_2/MWh of gross electric output based on a 12-month rolling average applies during ALL periods of operation, including periods of startup and shutdown.

Note that GHG BACT emission limits issued for numerous other EGUs do not include specific GHG emission limitations during periods of startup and shutdown. Rather, like the limits for the Pio Pico Energy Center (and which were upheld by the EAB), the limit applies during all periods of operation. Thus, a separate, specific limitation for periods of startup and shutdown is not necessary to ensure that GHG emissions from the CTGs are always subject to a BACT emission limit for ALL periods of operation.

iv. The GHG limit is the highest for similar facilities in the country and is less stringent than the proposed GHG NSPS**.**

RESPONSE: Contrary to the comment, the emission limit of 1,690 lb CO_2/MWh gross, based on a 12-month, is NOT the highest GHG emission limit for similar facilities in the country. In March 2014, the Oregon Department of Environmental Quality issued a construction permit No. 26-0235 for two simple cycle GE LMS100 CTGs with water injection. That permit includes a carbon dioxide BACT emission limit of 1,707 lb CO_2/MWh gross, based on a 365 day rolling average.

As stated in the permit application and in this letter, the Project has very specific project and business needs which require the combustion turbines to operate at low loads so that they may respond rapidly to potentially large grid load swings due to the loss of intermittent generating sources, especially renewable energy sources. As EPA has made clear, BACT emission limits are established on a case-by-case basis. And as noted above in EPA's *PSD and Title V Permitting Guidance For Greenhouse Gases*, in setting BACT limits, permitting authorities have the discretion to select limits that do not necessarily reflect the highest possible control efficiencies but that will allow compliance on a consistent basis based on the particular circumstances of the technology and facility at issue, and thus may consider safety factors unique to those circumstances in setting the limits.

To meet the project requirements, the Project must be able to operate the proposed CTGs at loads of 25%, potentially on an extended basis, so that the facility may ramp up quickly to meet the electric grid requirements and maintain a stable electric energy supply to the Region. And in accordance with EPA policy, just because other facilities may have other design and project requirements which allow lower GHG emission limits does not mean that it is inappropriate to establish a higher GHG BACT emission limit based on the particular circumstances of the technology and facility at issue. It is important to understand that BACT is not a method for defining the lowest GHG limit. Instead, as Pio Pico has clearly established, BACT is a limit which must be achievable at all times.[22] This facility, as proposed, meets this definition and therefore complies with Step 5.

With respect to the proposed NSPS emission limit for GHG emissions, the EPA addressed a similar comment for the EFS Shady Hills Project.[23] In summary, the proposed GHG NSPS, if finalized, would almost certainly NOT apply to the Project because the actual operation of the CTGs will not exceed one-third of the unit's potential electric output. The proposed rule defines electric generating units (EGUs) as units that sell more than one-third of their potential output to the grid. Under this definition, most simple cycle peaking stationary combustion turbines, including the Ocotillo units, would likely not be subject to the NSPS. In addition, in the proposed rule, the electric output is based on a three year rolling average to account for circumstances in which the CTG may operate at higher levels during years in which circumstances requiring peak duty service occur more frequently than usual.

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[22] *In re Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 74 (EAB Aug. 2, 2013).

[23] EPA's EFS Shady Hills LLC Project (PSD-EPA-R4013) – Response to Comments, at 5.

Finally, because the proposed NSPS is not final, the emission limit proposed in the NSPS does not establish a floor for GHG BACT determinations.

2. BACT for NOx emissions for the gas turbines.

A. Please respond to the argument that county rules require BACT for NOx but NOx BACT was improperly determined for the turbine being used for this project.

RESPONSE: It should be noted that the NOx BACT control technology analysis is not a PSD required BACT analysis, but instead an analysis required under local MCAQD rules for pollutants that do not trigger major PSD review. MCAQD provides guidance on how this BACT analysis should be performed. Either a standard top-down BACT analysis can be performed, or as an alternative the applicant can propose a BACT technology and limit for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department." The NOx BACT analysis for the Project relied upon BACT technologies and limits that were approved by these California agencies for identical turbine designs, and therefore complies with MCAQD requirements. However, APS will address these NOx BACT comments below.

The commenter has provided three reasons why the proposed NOx BACT limit is in error. First, the commenter argues that because the combined cycle turbines can meet all of the project specifications, that NOx BACT permit limits for *combined cycle plants* should have been included in the Ocotillo BACT analysis. This is not true because combined cycle CTGs cannot meet the project specifications and are therefore not feasible for the proposed Project. Combined cycle CTGs are so different from the proposed simple cycle CTGs that the requirement to consider combined cycle units would result in redefining the project. Combined cycle CTGs cannot meet the fast startup and ramp rates required for the Project and are therefore a technically infeasible control option. Thus, Maricopa County was correct to limit its review of NO_x BACT limits to simple cycle CTGs.

Second, the commenter argues that the most common reason used to justify a higher NOx emission limit for simple cycle turbines is the elevated exhaust gas temperatures (EGT) for simple cycle CTGs of at least 800 to 1,000 ^{o}F. The commenter then notes that "LMS100 turbines are not standard simple cycle turbines", with "significantly lower exhaust gas temperatures" of 760 ^{o}F. Although the commenter never mentions the EGT for combined cycle CTGs, the typical EGT for combined cycle units is 180 to 220 ^{o}F. As a result, the exhaust gas temperature for the proposed LMS100 CTGs is still far higher than combined cycle units. Therefore, it is not reasonable to say that because of the small difference in EGT from LMS100s compared to typical simple cycle CTGs that the LMS100's should be treated as if they were combined cycle units for purposes of the achievable NOx emission rate.

Third, the commenter states "many gas turbines, including simple cycle gas turbines, have been permitted and are operating with a NOx emission limit of 2.0 ppmvd at 15% O_2, based on a 1-hour average." The following table lists the examples cited by the commenter, and the type of facility actually permitted and constructed.

Plant Name	Type
Tracy Substation Expansion Project NV-0035	Combined Cycle
Langley Gulch Power Plant ID-0018)	Combined Cycle
Palomar Escondido – SDG&E 2001-AFC-24 with duct burners	Combined Cycle
Warren County Facility VA-0308 with or without duct burners	Combined Cycle
Ivanpah Energy Center, L.P. NV-0038 with duct burners	Combined Cycle
Gila Bend Power Generating Station AZ-0038	Combined Cycle
Duke Energy Arlington Valley AZ-0043 (Maricopa County)	Combined Cycle
Colusa II Generation Station 2006-AFC-9	Combined Cycle
Avenal Energy – Avenal Power Center, LLC 2008-AFC-1	Combined Cycle
Russell City Energy Center 2001-AFC-7	Combined Cycle
CPV Warren VA-0291	Combined Cycle
IDC Bellingham CA-1050	Combined Cycle
Oakley Generating Station 2009-AFC-4	Combined Cycle
GWF Tracy Combined-Cycle Project 2008-AFC-7	Combined Cycle
Watson Cogeneration Project 2009-AFC-1	Cogeneration

Every project cited in the comment is either a combined cycle unit, or a cogeneration unit which also has a heat recovery steam generator and has exhaust gas temperatures similar to combined cycle units. The commenter has provided no actual simple cycle CTGs permitted at a NOx emission rate of 2.0 ppmdv at 15% O_2. And California provides a clear distinction in its BACT guidelines for combined cycle CTGs versus simple cycle CTGs.

However, even if the commenter had found an example that does not mean that the County erred in establishing the NO_x limit at 2.5 ppmdv. As indicated in the Ocotillo application and in the application for the proposed Buckeye Generating Station, numerous construction permits for LMS100 CTGs have been issued with NOx BACT limits of 2.5 ppmdv, including the recent Pio Pico Energy Center in California.

3. BACT for PM/$PM_{2.5}$ emissions from the gas turbines.
A. Please respond to the argument that:

i. The net increase in PM and $PM_{2.5}$ from the project exceeds the PSD significance thresholds and, therefore, BACT is required.

RESPONSE: The application and the draft permit clearly recognized that the project emission increase does exceed the PSD significance thresholds and, therefore, BACT is required. The draft permit included BACT emission limits for PM and $PM_{2.5}$ emissions.

ii. The Step 1 BACT analysis for PM and $PM_{2.5}$ is flawed because it fails to identify commercially available good combustion practices for the turbines including steam injection.

iii. The Step 2 BACT analysis is flawed because it does not support the elimination of technologies such as DLN and steam injected gas turbines as being technically infeasible.

RESPONSE: GE has never built an LMS100 CTG with steam injection (either SAC or STIG variations) and does not currently offer the LMS100 with these designs. Therefore, these technologies are not an "available control option" for the LMS100 CTGs and may be eliminated as a BACT option in Step 1 of the BACT analysis.

Dry Low NOx (DLN) combustion is available for the LMS100 CTGs. However, as previously discussed, DLN is dismissed in Step 2 as technically infeasible because, while water injected LMS100 CTGs can achieve a NOx emission rate of 25 ppm continuously down to 25% load, DLN equipped units cannot achieve this NOx emission rate below 50% load. Furthermore, DLN equipped CTGs produce much more carbon monoxide (CO) than water injected CTGs. As a result, DLN equipped CTGs can only meet the CO BACT emission limit down to 75% load, while water injected CTGs can achieve the CO BACT limit down to 25% load. Because a CTG turndown of 25% is a major design criterion for the Project, the significant reduction in turndown capability for DLN equipped CTGs makes DLN equipped CTGs technically infeasible for these peaking units. Therefore, DLN would be dismissed under Step 2 as technically infeasible.

For the above reasons, steam injection and DLN combustion are unavailable or not technically feasible control technologies for the LMS100 CTGs and should therefore be eliminated as a BACT option.

iv. Step 4 of the BACT analysis is flawed because the choice of water injection ignores technically feasible alternatives and that have less adverse, energy, environmental and economic impacts.

RESPONSE: The commenter states that "In step 4 of its BACT analysis, the Applicant asserts that it has selected the best available control technology and thus further evaluation is not required. (Ap., Appx. B, p. 25.) However, the BACT analysis did not even identify the most effective control." As we have shown above, the other options identified by the commenter which may or may not reduce the achievable PM emissions for the proposed CTGs, including steam injection and DLN combustion, are not available or are not technically feasible control technologies for the Project. Therefore, the use of good combustion practices (water injection) is the only remaining available control technology, and further evaluation in Step 4 is not necessary.

v. Step 5 of the BACT analysis is flawed because it failed to consider the results of using alternative combustion systems. Further, there is no basis for raising the Pio Pico PM BACT level by 6%.

RESPONSE: As discussed above, the alternative combustion systems referred to in the comments, including steam injection and dry low NOx combustion, are not available or technically feasible control options for these CTGs. Furthermore, the commenter has presented no evidence that DLN combustion could actually reduce PM emissions from these CTGs as compared to the water injected units.

With respect to the basis for a PM BACT limit 6% higher than the Pio Pico PM BACT level, the commenter states that "However, the Application fails to explain how the sulfur content of natural gas affects PM and $PM_{2.5}$ emissions and fails to present any basis for raising the Pio Pico PM BACT limit by 6%, rather than some other value."

Sulfur in the natural gas will be oxidized to form sulfur dioxide (SO_2), and it may also be oxidized to form sulfur trioxide (SO_3). When the exhaust gas temperature reaches the acid dew point (which will only occur in the atmosphere or in a stack testing reference method sample train), SO_3 will react spontaneously with water to form sulfuric acid (H_2SO_4, $H_2SO_4 \cdot H_2O$, or $H_2SO_4 \cdot 2H_2O$). Sulfuric acid is "condensable" particulate matter which is measured using Reference Method 202 used for determining PM_{10} and $PM_{2.5}$ emissions. In addition, some of the sulfur dioxide in the sample flue gas may dissolve in the Method 202 sample train and eventually react with water to form sulfuric acid mist. This unintended reaction of SO_2 to form condensable particulate matter creates particulate matter which is an artifact of the reference method. In this context "artifact" means something observed (i.e. condensable particulate matter) in a scientific investigation or experiment (i.e., the reference method test) that is not naturally present but occurs as a result of the investigative procedure.

Because the CTGs have high excess oxygen levels, and because the CTGs will be equipped with oxidation catalysts, it is possible that relatively high percentages of SO_2 may be converted to SO_3. In the application, we indicated a 10% conversion rate on a mass basis, equal to a potential sulfuric acid mist emission rate of 0.06 lb/hr. EPA's revised BACT analysis for Pio Pico concluded that a BACT emission limit of 0.0055 lb/mmBtu would be appropriate. An emission rate of 0.0055 lb/mmBtu is equal to a mass emission rate of 5.34 lb/hr at the rated heat input of 970 mmBtu per hour for the proposed GTs. The addition of the sulfuric acid mist emission rate would make the limit 5.4 pounds per hour, which is what has been proposed in the application.

4. **BACT for PM/$PM_{2.5}$ emissions from the cooling tower.**
   A. **Please respond to the argument that alternative cooling methods to the hybrid cooling system design were not evaluated.**
      i. Dry cooling was not evaluated

RESPONSE: APS did consider dry cooling as part of the power plant planning process. The use of dry cooling was rejected primarily because the use of dry cooling would result in a substantial reduction in the peak electric output of the power plant, especially during typical peak load conditions with high ambient temperatures.

Under Step 1 BACT analysis, there are three possible cooling options for the plant: 100% evaporative cooling which uses only cooling towers or wet surface to air coolers (WSACs), 100% dry air cooled heat exchangers (ACHEs) which use no water, and a hybrid system consisting of a combination of ACHEs and WSACs. The following are the estimated plant performance and output levels at an ambient air temperature of 105 ^{o}F, which is a critical design condition for this plant:[24]

Estimated GE LMS100 CTG performance at the Ocotillo Power Plant for different types of intercooler cooling systems at 105 ^{o}F and with inlet chilling.

Cooling System Design	Gross Output, MW	Net Output, MW	Net Unit Heat Rate, Btu/kWh
100% Dry	92.2	86.2	9,566
100% Evaporative	107.4	102.4	9,125
Hybrid	107.4	102.2	9,138

From the above table, the use of 100% dry cooling would reduce the net plant output at an ambient temperature of 105 ^{o}F by 16.1 MW per CTG (a 15% reduction), or a total plant derating of approximately 80 MW. The use of 100% dry cooling would also reduce the CTG efficiency and increase GHG emissions per MWh of electric output. At the same ambient air temperature, the hybrid system would have only a minimal impact on the plant output and efficiency, yet the hybrid system would reduce water consumption by 32%, from 207 gallons per MWh for the 100% evaporative system to 141 gallons per MWh for the hybrid system.

This reduction in plant capacity on hot summer days would have a very high cost. At a typical capacity price of $3,000 per MW per month, the annual cost for this plant derating would be approximately $2,916,000 per year. Based on the revised cooling tower BACT analysis, the potential PM, PM_{10}, and $PM_{2.5}$ emissions for the proposed hybrid cooling tower are 5.57, 1.75, and 1.05 tons per year, respectively. If a 100% dry cooling system eliminated these emissions, the cost effectiveness for the use of 100% dry cooling as a BACT control option would be $524,000 per ton of PM controlled, $1,666,000 per ton of PM_{10} controlled, and $2,777,000 per ton of $PM_{2.5}$ controlled. These are extremely high, economically infeasible costs. These costs do not include the lost energy sales during peak power periods when the cost of replacement power is typically very high. Therefore, the use of a dry only cooling system is also an economically infeasible BACT control option for the control of PM, PM_{10}, and $PM_{2.5}$ emissions for this Project.

[24] *Arizona Public Service Company Ocotillo CT 3-7 Expansion Project Cooling System Study*, Kiewit Power Engineers, Project No. 2013-027, Rev 0 – June 6, 2013.

The capital and auxiliary power requirements are also higher for the 100% dry cooling systems. The capital costs for the hybrid system are estimated at \$9,888,000 as compared to \$13,813,000 for the 100% dry air cooled heat exchanger cooling system.[25] To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is \$336,765. If a 100% dry cooling system eliminated the hybrid cooling system emissions, the cost effectiveness for the use of 100% dry cooling as a BACT control option – based only on the additional capital cost - would be \$60,460 per ton of PM controlled, \$192,000 per ton of PM_{10} controlled, and \$321,000 per ton of $PM_{2.5}$ controlled. These costs also demonstrate that the use of a dry only cooling system is an economically infeasible BACT control option for the control of PM, PM_{10}, and $PM_{2.5}$ emissions for this Project. Thus, the use of 100% dry cooling systems may be eliminated in Step 4 of the BACT analysis.

ii. Water treatment of the makeup water to the cooling tower was not evaluated.

RESPONSE: The potential PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling tower are a function of the maximum expected circulating water total dissolved solids (TDS) concentration. The TDS concentration in the circulating water can be predicted from the makeup water TDS concentration and the expected cycles of concentration (cycles) for the cooling tower. Cycles are the ratio of the concentration of a soluble substance such as chloride in the circulating water to the concentration of that substance in the makeup water. So the commenter is correct that for a well water TDS concentration of 800 ppm and seven cycles of concentration, the circulating water would have a TDS concentration of 5,600 ppm. However, the cooling tower can be operated at higher cycles of concentration to reduce makeup water requirements. Therefore, the makeup water TDS level and the cycles of concentration are not the determining factor for the maximum circulating water TDS level and the potential emissions from the cooling tower.

It is important to understand that demineralizing the incoming water with reverse osmosis will not change the maximum TDS concentration in the circulating cooling water. And because potential PM, PM_{10}, and $PM_{2.5}$ emissions from cooling towers are a function of the *circulating water* TDS (NOT the makeup water TDS), the use of demineralized makeup cooling water would not affect the maximum potential emissions from the cooling tower. Rather, demineralizing the makeup water would increase the *cycles of concentration* which the cooling tower could operate at, but it would not necessarily change the maximum TDS concentration in the circulating cooling water. Therefore, the commenter is incorrect that "Removing 95% of the TDS from the cooling tower makeup water would reduce PM,

[25] *Arizona Public Service Company Ocotillo CT 3-7 Expansion Project Cooling System Study*, Kiewit Power Engineers, Project No. 2013-027, Rev 0 – June 6, 2013, page 7-4.

$PM_{2.5}$, and PM_{10} emissions from the cooling tower by an equivalent amount." Treating the makeup water would only reduce the makeup water requirements; it would not reduce potential PM emissions from the cooling tower.

iii. Lower drift rate losses were not evaluated as BACT.

RESPONSE: The commenter is incorrect that the Longview Power Plant requires mist eliminators designed with 0.0002% drift loss. The final air pollution control construction permit issued by the West Virginia Department of Environmental Protection effective March 2, 2014, Permit No. R14-0024, condition A.1.30a., requires "Emissions of PM and PM-10 shall be controlled with a 0.002% drift eliminator or an equivalent control technology." Thus, the commenter is off by a factor of 10, and the proposed drift eliminator with a design drift loss of 0.0005% is more stringent than that required for Longview Power.

Note that the cooling towers for the Longview Power facility, a 900 MW coal-fired facility, will be different than those proposed for the Project. It is also important to note that the permit for Longview Power does not require any cooling tower drift loss performance tests.

5. NO_x emissions cap.
Please respond to the arguments supporting the statement that the NO_x emissions cap is unenforceable.

COMMENT A: One commenter discusses various generic protocols for rounding of numbers to conclude that a net emission increase of 39.5 tons per year (tpy) of NO_x represents a major modification. The commenter presents two arguments. First, that the computed emissions increase value should be rounded to the significant digits corresponding to the Significant Emission Rate (SER); second, that the emissions increase should be computed to only two significant digits. Neither argument is correct.

With regards to comparing the computed emissions increase to the SER, it is not necessary to round the calculation to determine applicability, because EPA treats the SER as an "absolute" applicability threshold. This means that any emission value below the threshold is not significant and any emission value at or above the threshold is significant; neither the EPA nor other permitting agencies round-up, as the commenter asserts. For example, in the EPA Region 9 PSD permit for the Mt. Poso Cogeneration Company, Permit Number SJ 86-09, January 2010, the EPA Statement of Basis lists the project net emission increases for NO_x and SO_2 as 39.5 tpy, and concludes that the increases are below the 40 tpy SER. The Project did not trigger PSD review for those pollutants. This is the standard approach that EPA and States follow to determine when the emissions increase for a project equals or exceeds the absolute limit of the SERs.[26]

[26] *See, e.g.,* Statement of Basis BAQ Engineering Services Division, South Carolina Department of Health and Environmental Control, Ameresco Federal Solutions, Permit Number 0080-0144-CC, Nov. 21, 2014; *and* Depart.

EPA provided an example of this approach in its Draft New Source Review Workshop Manual when it used emissions increase values reported to one decimal place in providing example methods for determining NSR applicability.[27] This is also the same manner in which EPA treats significant rates for the purposes of increment modeling.[28] And, similarly, EPA defines potential to emit (PTE) as the "absolute maximum" that a stationary source could emit, and recognizes that enforceable synthetic minor emission limitations in any amount below an applicability threshold can prevent a source from triggering requirements based on that threshold.[29]

With regards to the commenter's second argument, EPA does not dictate a level of specificity for computing an emissions increase, nor does EPA require States to apply significant digit protocols. Given this, many States have developed their own policies for recording and reporting emissions information. For example, the Arkansas Department of Environmental Quality rounds emissions limitations for criteria pollutants to one decimal place in accordance with the Department's policy;[30] the Louisiana Department of Environmental Quality generally requires emissions to be reported to two decimal places;[31] and, Oklahoma reported a facility's emission increase using between two and four decimal places, despite computing these values using emissions factors with as few as two significant digits.[32] Finally, it must be noted that emission calculations in spreadsheets are based on a numeric precision on the order of 15 digits; there, an emission limit of 2 ppm in a spreadsheet is carried through emissions calculations effectively with 14 trailing zeros, eliminating rounding considerations for those calculations.

Notwithstanding these differences, rounding emissions increase calculations to always account for significant digits for purposes of major NSR permitting, as the commenter suggests, could have other unintended consequences during NSR review. For example, a 149 tpy emissions increase would be rounded down to 100 tpy if one assumes a value in the emissions calculation only includes one significant digit, which could alter for example the requirement amount of emission offsets.

Therefore, in light of the evidence submitted, 39.5 is clearly an acceptable number and the standard upon which a review should be made.

Findings of Fact and Order New Source Review Amendment, New England Waste Service of ME, Inc., A-850-77-7A, State of Maine Depart. Of Environmental Protection, Feb. 18, 2011; *and* Memorandum *from* Kathleen Henry, Chief Permits Programs Section, Region 3, U.S. Environmental Protection Agency *to* Leif Ericson, Quality Program Manager, Pennsylvania Department of Environmental Quality, Feb. 9, 1999 (regarding P.H. Glatfelter's Pulp and Paper Mill).

[27] Draft New Source Review Workshop Manual Prevention of Significant Deterioration and Nonattainment Area Permitting, United States Environmental Protection Agency, Oct. 1990.

[28] *See* 23 FR 40657 (explaining that increments are absolute limits).

[29] *See Memo.* From Terrell E. Hunt, Associate Enforcement Counsel, and John S. Seitz, Stationary Source Compliance Division, United States Environmental Protection Agency *to* Addressees. Guidance on Limiting Potential to Emit in New Source Permitting. June 13, 1989.

[30] *See* Response to Comments, Nucor Corporation, Nucor Steel Arkansas, AFIN#47-00233, Permit 1139-AOP-R16

[31] *See* Louisiana Application for Approval of Emissions of Air Pollutants from Minor Sources, Form 7200 r01, 10/22/10.

[32] *See Memo.* From Dawson Lasseter, Chief Engineer, Oklahoma Department of Environmental Quality Air Quality Division. Evaluation of Permit Application No. 99-028-C (PSD)(M-1), Calpine Oneta Power, L.P.. May 30, 2001.

COMMENT B: The commenter next states that the draft permit does not require that turbine NO_x emissions from malfunctions, or NO_x emissions from the new emergency generators, be included in the NO_x actual emission calculations. As described in footnote c to Table 4 in the draft permit, GT3-GT7 NOx emissions will be directly and continuously measured using CEMs, which will aggregate all emissions during all modes of operation, so that emissions from malfunctions will be included in the annual emission calculations. It appears that the format of Tables 2, 3, and 4 in the draft permit that list emission limits may be ambiguous and causing some confusion on this issue. Table 2 lists emission limits that apply during all operating modes including startup and shutdown for all pollutants except NOx and CO, for which separate startup and shutdown limits apply as listed in Table 3.

The actual hours of operation will be used in combination with the maximum hourly emission rates (based on full load operation and the relevant NSPS Tier certified NO_X emission rate) to conservatively calculate monthly emergency generator NO_X emissions, which will be summed into the Project-wide NO_X actual annual emissions.

COMMENT C: Riley, Carlock and Applewhite states that operational or production limits, in addition to emission limits, are required to limit PTE, and references a 1987 court finding. It should be noted in that 1987 Louisiana Pacific case, the facility had proposed an emission limit without any compliance demonstration methods or operating limits. That is not the situation for the Ocotillo draft permit. The draft permit contains operational limits, expressed as fuel use limits, that limit PTE for most pollutants. In EPA's Response to Comments on the Pio Pico PSD permit application[33], EPA discussed operating limits on PTE and stated that "(l) omitting the fuel use achieves the same objective as limiting the hours of operation". The draft Ocotillo permit also contains emission caps for other pollutants, including Project-wide NO_X and facility-wide PM_{10} emissions, with detailed compliance demonstration methods that include CEM data, fuel use monitoring, and stack test derived emission factors. APS has requested NO_x and PM_{10} emission caps under which it can vary operations of individual emission units while still maintaining actual plant-wide emissions below the caps. This allows greater operational flexibility as compared to assigning fixed operating limits to individual units or specific modes of operation.

The fact that the full potential emissions of each emission unit do not sum up to the requested emission cap does not mean the cap is invalid or unenforceable. Instead, it reflects the reality that not every emission unit will emit at its full potential during the course of a year, and that APS has the flexibility to trade-off operations between units while still managing total emissions to be below the emission caps. The compliance demonstration methods contained in the draft permit will allow APS to demonstrate continuing compliance with all the emission caps, therefore the emission caps are valid and enforceable.

[33] Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center, EPA Region 9, November 2012.

6. **Comments 1, 2, and 3 from the non-Sierra Club commenters all turn on whether the project is a reconstruction and will be addressed as a single response.
Please respond to the argument that the project is a major modification and would require a significant net emissions increase for PM_{10} and thereby triggers nonattainment area new source review for that pollutant.**

   RESPONSE: Each of the comments 1 through 3 from Riley, Carlock, and Applewhite will be addressed separately, as well as the comment that the project is a major modification for PM_{10}.

   Regarding comment 1, the Ocotillo air permit application already contains a detailed discussion regarding the applicability of SIP Rule 21. The conclusions from that analysis are that the Ocotillo plant is not a major source of nonattainment pollutants regulated by the SIP rules (under both the plant-wide and "installation" definitions of source); furthermore, because SIP Rule 21 installation permit requirements and reconstruction provisions only apply to major sources in nonattainment areas, they do not apply to the Project.

   Regarding Comment 2, APS previously provided a regulatory analysis[34] of the reconstruction provisions. Some of the key points discussed in this analysis include:

   - For purposes of determining whether a reconstruction has occurred, one must look to the *existing* facility itself to determine whether components were replaced *at that facility*. That the focus is on the work done at the existing facility (as opposed to at a new unit being constructed on the same site) is made abundantly clear by EPA's usage of the phrase "of which" in its definition of "existing facility".
   - A search of EPA's Applicability Determination Index reveals that the database is replete with reconstruction applicability determinations wherein EPA focused on the existing facility on which the work was done, rather than work at a new facility being constructed somewhere else on the site, as Industry Commenter erroneously alleges.
   - Almost 40 years of EPA rule-making, applicability determinations, and policy guidance make clear that for purposes of determining whether there has been a reconstruction of an existing facility, the focus is on the apparatus on which the work is taking place, not on entirely new units being constructed at the same site.

   In summary, it has been shown above that neither SIP Rule 21 nor Rule 240 reconstruction provisions apply to this Project.

Finally, the commenter asserts that "the project is a major modification and would require a significant net emissions increase for PM10 and thereby triggers nonattainment area new source review for that pollutant". This comment ignores the fact that APS requested and MCAQD imposed a facility wide PM_{10} emissions cap, with specific compliance determination requirements. This results in the Ocotillo Plant being classified as a minor PM10 source under the MCAQD nonattainment rules, and therefore the

[34] Letter from Michael T. Kafka, Senior Counsel, APS to Maricopa County Air Quality Department dated November 7, 2014.

Project cannot trigger nonattainment area new source review. Please also see our response to comment 7 below.

7. **Both commenters questioned the validity of voluntary emissions cap for PM_{10}/$PM_{2.5}$. One commenter argued that the regulations do not authorize the creation of an emissions cap at the same time as the major modification would occur to avoid the imposition of non-attainment area new source review. Both commenters maintain that the emissions cap as proposed is not sufficiently enforceable and, therefore, is invalid.**

   A. **Please respond to the argument that a voluntary emissions cap for PM_{10}/$PM_{2.5}$ is invalid.**

   RESPONSE: One commenter asserts that a facility cannot request a limit on potential emissions to reclassify the source as a minor source at the same time some other physical change at the facility is proposed. This in incorrect, as EPA permitting policy clearly allows for this type of permitting action. For example, a letter from Pamela Blakley, Chief Air Permits Section, EPA Region 5 to the Indiana Department of Environmental Management (IDEM) dated December 7, 2006, discusses this situation for a facility operated by General Shale. General Shale's facility had two brick manufacturing lines with both actual emissions and PTE above the major stationary source thresholds. The facility requested a permit that would authorize installation of controls on the two existing lines such that the source would become minor, and at the same time construct a third line. IDEM required that Lines 1 and 2 come into compliance with the synthetic minor limit before actual construction on line 3 could begin. The critical determination was that, at the time construction would commence on line 3, the existing stationary source would be minor. Another example is for the SRP Kyrene plant, where the source requested a facility-wide PM_{10} emission limit of 68.5 tpy to be classified as a minor source in Maricopa County's PM_{10} nonattainment area concurrent with an expansion project at the facility. This project is very similar to the Project, except that the proposed Ocotillo PM_{10} facility-wide emission limit is lower at 63 tpy. In a letter from EPA Office of Air Quality Planning and Standards to Hunton and Williams, EPA determined that Maricopa County could conclude that Kyrene would not be subject to nonattainment NSR for the project and could be reclassified as a minor source. Based on these two examples, it is clear that APS can request a PM_{10} emission limit to reclassify the Ocotillo plant as a nonattainment area minor PM_{10} source as part of the Project permitting, thereby not triggering the nonattainment area new source review requirements (it should be noted that the requested PM_{10} emission cap must be in effect before the date the first new emission unit from the Project begins operation).

   B. **Please respond to the argument that the PM_{10} cap is not enforceable as applied to PM_{10} emissions from GT1 and GT2 as well as the gas turbines and the cooling tower.**

   RESPONSE: One commenter asserts that the PM_{10} emission cap is unsupported and facially exceeded, based on the fact that the potential emissions of each emission unit do not sum up to be equal to the requested emission cap. APS has requested an emission cap under which it can vary operations of individual emission units while still maintaining the facility-wide PM_{10} actual emissions below the cap. This allows greater operational flexibility than assigning fixed operating limits to individual units. The fact that the potential emissions of each emission unit do not sum up to the requested emission cap does not mean the cap is invalid. Instead it reflects the reality that not every emission unit will emit at its full potential during the course of a year, and that APS has the flexibility to trade-off operations between units while still managing emissions to be below the PM_{10} cap.

To determine compliance with the PM_{10} emission cap, the draft permit contains specific compliance demonstration methods for calculating PM_{10} actual emissions for the various emission units at the facility, as described below.

For GT1 and GT2, the draft permit contains a compliance demonstration condition that PM_{10} emissions during normal operations, startup/shutdown periods, and tuning/testing periods be calculated using monitored fuel flow and emission factors from the U.S. EPA document AP-42 Section 3.1 (unless an alternative emission factor can be demonstrated to the satisfaction of the Control Officer and the Administrator to be more representative of emissions). See footnote f of Table 4 in the draft permit. This footnote, and footnote e that applies to the new turbines GT3-GT7, should be revised to clarify that malfunction emissions are also included in this calculation (in effect, the total fuel usage is used in the PM10 emission calculation for all turbines). It is generally acknowledged that the AP-42 Section 3.1 natural gas PM_{10} emission factor for stationary combustion turbines conservatively estimates actual emissions. However, APS is hereby requesting that the permit include a PM testing requirement on one of the existing GT1 and GT2 units to develop an emission factor that can be used to accurately calculate PM10 emissions from these units, as part of the PM10 emission cap compliance demonstration.

The commenter asserts that PM_{10} emissions associated with ammonia slip from the SCR control system have not been properly accounted for. This is not correct, as the PM10 testing methods will measure both filterable and condensable PM, including ammonia related emissions.

The commenter states that the Permit should be revised to require the use of a PM CEMS, include more frequent stack testing for PM_{10} at all turbines, or include continuous indicator monitoring, e.g., opacity, to address those periods when direct stack testing is not conducted. The commenter asserts that these additional permit terms are required to address events such as SCR catalyst cleaning or wind storms that increase particulate matter in inlet air and that without such conditions there is a high likelihood that Ocotillo will emit PM_{10} at a rate that would trigger major nonattainment NSR.

Please note that the proposed Ocotillo facility-wide PM_{10} emission cap is set at 63 tons per year, a full 7 tpy below the threshold that triggers non-attainment NSR. It is extremely unlikely that PM_{10} emission increases from infrequent occurrences of events could contribute 7 tpy to total plant wide emissions. Second, high levels of PM in the inlet air would erode the turbine blades and could damage the turbines. As a result, the CTGs are equipment with inlet air filtering and misting systems which are designed to reduce the inlet air concentrations of particulate matter (PM). Third, based on a review of other permits for gas-fired turbines, there are no permits that have required the installation of PM CEMs or opacity monitors. In fact, units that are natural gas-fired units are exempt from the opacity monitoring requirements under the Acid Rain Program in 40 CFR Part 75For all of these reasons, there is no need, nor scientific or legal basis, to require additional permit conditions.

For the cooling tower, the draft permit contains a compliance demonstration condition that PM_{10} emissions be calculated based on the full design recirculation rate of the tower, the design drift factor, the operating hours for the tower, and the measured TDS concentration. The draft permit requires that APS monitor and record the TDS content of the Cooling Tower water on a monthly basis. The use of the full design flow rate in these emission calculations is a conservative assumption, and will result in higher calculated PM10 emissions than will actually occur. Although the compliance demonstration method assumes that operating hours for the cooling tower are available, APS is hereby requesting that the permit include a requirement to record the monthly operating hours of the cooling tower, and to clarify that the PM_{10} emissions are calculated on a rolling 12-month basis using measured operating hours and TDS concentrations, along with the maximum design water flow rate. The particle size multipliers used in the permit application and in the TSD are based on past cooling tower tests in Maricopa County, and therefore are justified and appropriate.

Finally, the PM_{10} emissions from both the two new and one existing emergency generators will also be calculated and added to the facility-wide actual emissions. The draft permit requires that the hours of operation for each of the emergency generators be recorded as well as limits the hours of operation for the emergency generators. The actual hours of operation will be used in combination with the maximum hourly emission rates (based on full load operation and the relevant NSPS Tier certified PM_{10} emission rate) to calculate monthly emergency generator PM_{10} emissions, which will be summed into the facility-wide PM_{10} actual annual emission calculations and demonstrate compliance with the emission cap.

8. **Comments 6, 7, 8, 9, 10, 11, and 18 all pertain to the requirement in Section 165 of the Clean Air Act and 40 CFR Section 52.21 that an applicant for a PSD permit demonstrate, using air quality models, the facility's emissions of PSD-regulated pollutants will not cause or contribute to a violation of the applicable NAAQS; or consuming the applicable PSD increments including Class II area increments and Class I area increments intended to protect visibility. The PSD regulations require that the air quality analysis be based on background ambient air quality; specific guidance as to model choice and protocol; model receptors; load screening and stack parameters; cumulative impact analysis and NAAQS-specific issues. The commenters cite a list of what are asserted to be deficiencies in the modeling and failure to support the findings required by 40 CFR Section 52.21.**

   A. **Please respond to the cited deficiencies and provide discussion that supports APS' overall conclusions from the air impact analysis.**

RESPONSE: Each of these comments from Riley, Carlock, and Applewhite will be addressed separately.

Response to Comment 6 - This comment asserts that an air quality analysis should have been conducted for PM_{10}, based on the flawed argument that the Project is a major modification for PM_{10}.

See the first response to Maricopa requested item 7 above, which confirms that the Ocotillo plant will be a minor PM_{10} source after the Project and is not a major modification. In any case, because PM_{10} is a nonattainment pollutant, a standard air quality analysis would not be required for a major source or modification (instead, the nonattainment rules contain separate provisions such as offsets to address the air quality impacts of significant emission increases).

Response to Comment 7 – This comment states that Class I visibility impacts were not addressed. The Project triggers PSD review for GHG, CO, PM, and $PM_{2.5}$ pollutants. There are no Class I Federal Land Manager (FLM) requirements to perform visibility analyses for GHG and CO pollutants, as they do not cause visibility impacts, and any Class I analyses would focus on $PM_{2.5}$ impacts to visibility ($PM_{2.5}$ has a far greater effect on visibility than coarse PM emissions). The closest Class I area to the Project site is the Superstition Wilderness, located approximately 43 km to the east of Ocotillo. Based on the FLM visibility assessment guidance in the "Federal Land Manager's Air Quality Related Values Workgroup Phase I Report", Revised October 2010 (FLAG), the "Q/D" screening threshold technique is used to determine if there is the potential for visibility impacts and if a detailed analysis is warranted (Q refers to the emission increases of PM10, SO2, sulfuric acid mist, and NOx emissions and D is the distance from the source to the Class I area). Given that the emission increases of these pollutants for the Project, it is evident that an AQRV analysis will not be required for any Class I area further than 50 km from the Ocotillo plant (this will be fully documented in an updated air quality impact analysis). However, because the Project is located within 50km of the closest boundary of the Superstition Wilderness Class I area, a near field VISCREEN analysis will be performed as part of the updated impact analysis to further support the conclusion that the Project will not result in adverse Class I visibility impacts.

Response to Comments 8 and 9 - These comments state that "APS failed to show that the project would not cause violations of the NAAQS for NO_2, ozone, or PM_{10}", and "APS should have provided modeling to demonstrate compliance of the NAAQS in accordance with ADEQ policy and past practices". Standard EPA PSD rules only require air quality impact analyses for PSD regulated criteria pollutants that trigger PSD review. For the Project those pollutants include CO and $PM_{2.5}$. As part of the updated air quality impact analysis, APS will also analyze the air quality impacts for relevant "non-PSD" pollutants. The commenter also continues to restate the flawed argument that the Project triggers major modification review for PM_{10} and NO_X; refer to response to Maricopa item 7 for further discussion on this issue.

Finally, with respect to *SSSR v. ADEQ*, it is hard to provide any response on the merits of that decision, as the opinion merely summarizes the parties' arguments and announces a ruling; it contains no analysis, or even enough facts to determine whether the issues in that case are similar to those here.[35] In any event, APS will be presenting additional NAAQS modeling analyses for relevant "non-PSD" pollutants in an updated air quality impact analysis.

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[35] We also not that decision has been appealed. We submit it is unlikely to survive appeal, given the utter lack of anything resembling reasoning or analysis in that decision.

Response to Comment 10 – This comment states that "Modeling must reflect representative operations, which in this case means that the modeling should have been based on at least two scenarios given the intended use and lack of any operational restrictions: operation at the maximum capacity for 24 hours and multiple startup and shutdown events", and further that the record "does not demonstrate what baseline was used by APS". These comments are unfounded. Page 34 of the Technical Support Document (TSD) discusses the basis of the modeled scenarios. For $PM_{2.5}$, a load screening analysis was performed that identified the worst-case scenario as the 100% load, full capacity scenario. This scenario was modeled for 24 hours every day for all subsequent $PM_{2.5}$ modeling. For CO modeling, the TSD states that the maximum short-term CO emission rates occur during startup /shutdown operation, and that these maximum emissions were modeled with the 25% load stack parameters to conservatively determine the CO ambient impacts. In effect, the CO scenario modeling assumes that all 5 turbines were simultaneously and continuously in startup mode for 24 hours each day, which greatly overstates the actual emissions and air impacts. Clearly, the modeled scenarios do address a range of operating scenarios, and are representative and conservative for estimating ambient impacts.

It is unclear what "baseline" the commenter is referring to, since that term typically refers to baseline actual emissions and not any modeling related term (note that while PSD increments do have a baseline air concentration, because the impacts form the Project are less than the Significant Impact Levels, a PSD increment analysis was not necessary).

Response to Comment 11 – This comment states that "APS failed to collect pre construction monitoring data or identify representative ambient monitoring data" for "determining the background conditions". Given the numerous MCAQD ambient monitoring sites near the Ocotillo plant, information is readily available on representative nearby monitoring data. An updated air quality impact analysis will be submitted that discusses the available data and demonstrates how this data meets the PSD preconstruction monitoring requirements.

Response to Comment 18 - This comment simply restates previous comments that have already been addressed above, and does not raise any new technical or regulatory issues.

B. Please provide a modeling protocol that follows the principles of 40 CFR Part 51, Appendix W and the "Air Dispersion Modeling Guidelines for Arizona Air Quality Permits" prepared by the Arizona Department of Environmental Quality.

RESPONSE: An updated modeling protocol and report will be prepared in the requested ADEQ format.

C. Please describe in detail how required elements of the air quality inputs and analysis were met for this project.

RESPONSE: The required elements for an air quality analysis include a project description, regulatory status description, discussion of any required meteorological and air quality monitoring data, justification for model selection and model options, receptor grid and meteorological data processing procedures, emission source treatment, load screening to determine worst-case scenarios, presentation of Project-only results, presentation of additional NAAQS and PSD increment analyses (only if the Project impacts are greater than the Significant Impact Levels), an additional impacts analysis, and if necessary a Class I area impacts analysis. The Ocotillo Permit Application describes all these elements of the air quality analysis. The only components of PSD air quality analyses that require supplemental information are the visibility modeling for the portion of the Superstition Wilderness Class I that is within 50 km of Ocotillo, and the description of existing air quality monitoring data that meets PSD preconstruction requirements. The updated modeling protocol and report will include this supplemental information.

9. **Comment 12 asserts that GHG emissions have been underestimated because they do not include CO_2 emissions from the oxidation catalysts on the turbines and emergency generators. Please respond.**

   RESPONSE: This comment is not correct. In all emissions calculations for potential GHG emissions in the application, 100% of the carbon in the natural gas is assumed to be converted to carbon dioxide (CO_2). The small amount of carbon monoxide subsequently converted to CO_2 by the oxidation catalysts on both the CTGs and diesel engines is therefore already included in the potential CO_2 emission calculations. Therefore, all potential CO_2 emissions have been included.

10. **Comment 15 asserts that the MCAQD should require GHG BACT for pipeline fugitive emissions. Please respond.**

    RESPONSE: We believe that MCAQD has the discretion to conclude that fugitive pipeline methane emissions are so small as to be inconsequential. However, APS will submit a control technology review and is proposing BACT requirements for the natural gas pipelines at the Ocotillo plant.

11. **Comment 16 says that the application does not accurately characterize turbine startup times. Please respond.**

    RESPONSE: EPA Region 9 considered various definitions of startup during development of the Pio Pico PSD BACT analysis and PSD permit, and determined that defining startup as "the period beginning with ignition and ending 30 minutes later" best addressed the short startup times associated with LMS100 turbines used in a simple cycle peaking mode. The use of 30 minute startup times for LMS100 turbines was also recently proposed by a similar project in Maricopa County, the Buckeye Generating Station, and MCAQD has incorporated this same startup definition in a draft permit for that facility. Based on EPA's analysis and information submitted in APS' permit application, the use of a 30 minute startup definition is appropriate and justified.

12. Comment 17 states that the application fails to accurately characterize the number of startups and shutdowns that will occur during normal operations. Please respond.

RESPONSE: This comment asserts that the air quality modeling assumes two startup/shutdown sequences per day, and therefore the permit must have a similar operating limitation. However, it is incorrect that the air quality modeling assumes two startup/shutdown sequences per day. Instead, as described in the Ocotillo permit application Section 6.6, the MCAQD TSD, and in response 8 above, for the CO analyses the modeling assumed that all 5 turbines were simultaneously and continuously in startup mode for 24 hours each day, which greatly overstates the actual CO emissions and air impacts. For other pollutants the worst-case 100% load operating scenarios were modeled, since those caused the highest model predicted impacts. Therefore, because the modeling was not limited to a specific number of startups and shutdowns per day, a daily limitation is not required.

Thank you for your continued work in the review of our application for the Ocotillo Modernization Project. If you have any questions regarding this letter, you may contact me or Anne Carlton.

Sincerely,

Charles Spell
Director of Environmental