SANTA BARBARA COUNTY
AIR POLLUTION CONTROL DISTRICT

Draft Staff Report for:

Amended Rule 360 - Boilers, Water Heaters, and Process Heaters (0.075 – 2 MMBtu/hr)

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Our Mission

Our mission is to protect the people and the environment of Santa Barbara County from the effects of air pollution.

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1. EXECUTIVE SUMMARY

Rule 360 is a point-of-sale rule that regulates oxides of nitrogen (NOx) and carbon monoxide (CO) emissions from boilers, water heaters, steam generators, and process heaters with a rated heat input capacity within the range of 0.075 to 2.0 million British thermal units per hour (MMBtu/hr). The proposed amendments to this rule reduce the NOx limits for these units. The proposed amendments require that, beginning on January 1, 2019, newly installed and modified units that are fired on natural gas must be certified to a NOx emission limit of 20 parts per million by volume (ppm). The amendments fulfill a commitment from the Santa Barbara County Air Pollution Control District's (District's) *2016 Ozone Plan*, and they are based on similar requirements that have been implemented in other air districts throughout California for the last 5 years.

2. BACKGROUND

2.1 Source Category Description

There are many of types of boilers, water heaters, steam generators, and process heaters subject to Rule 360. They range from smaller units that are used to provide domestic hot water for a school or hotel to larger units that produce high pressure steam for use in industrial processes. Other typical applications for this source category may include: space heating, food processing, garment laundering, or equipment sterilization. All of these devices function by combusting a fuel and transferring the heat of combustion to water or to a process stream.

The two main pollutants of concern for a combustion process are oxides of nitrogen (NOx) and carbon monoxide (CO). Because the proposed emission limits are already required in other California air districts, units that meet the emission limits are readily available. The design features that allow units to meet the lower limits typically reduce thermal NOx formation by changing the flame characteristics to reduce the peak flame temperature. Some of the design principles used in low-NOx burners include staged air burners, staged fuel burners, and pre-mix burners, all of which provide a well-controlled, efficient combustion process with minimized emissions.

2.2 Rule 360 Background

The District's Governing Board initially adopted Rule 360 on October 17, 2002. As a point-of-sale rule, Rule 360 applies to any person who supplies, sells, offers for sale, installs, or solicits the installation of boilers, water heaters, steam generators, and process heaters with a rated heat input of 0.075 MMBtu/hr to 2.0 MMBtu/hr. Affected persons include manufacturers, plumbing wholesalers, supply stores, contractors, and end-users of said equipment. This point-of-sale approach allows the District to achieve NOx emission reductions without forcing the immediate replacement of existing units, which places a financial burden on the end-user.

The 2002 rule implemented a NOx emission limit of 30 ppm for units 0.4 - 2.0 MMBtu/hr and 55 ppm for units with a rated heat input of 0.075 - 0.4 MMBtu/hr. To verify that these emission limits are met, Rule 360 requires that the manufacturers certify their units through the District's certification program. The District has also previously accepted the similar South Coast Air Quality Management District (SCAQMD) certification process as required by their Rule 1146.2. Both of these processes require that the manufacturer obtain a certification source test from an independent testing laboratory for each unit model in order to verify compliance with the applicable emission limits. The manufacturer is then required to submit the certification source test as part of a compliance report that identifies the manufacturer, brand name, model, and description of the unit being certified. SCAQMD has worked extensively with manufacturers subject to SCAQMD Rule 1146.2 to certify thousands of units and provides a list of certified units on their website. Only a handful of manufacturers have ended up using the District's certification process since many of them have already had their units certified by the SCAQMD.

The District submitted the initially adopted Rule 360 to the California Air Resources Board (CARB) for forwarding to the EPA as an amendment to the State Implementation Plan (SIP).[1] EPA finalized their approval of Rule 360 on October 14, 2003. The proposed amendments to Rule 360 are anticipated to be sent to the EPA for SIP approval as well.

2.3 Mandates

Ground level ozone is a secondary pollutant formed from photochemical reactions of the precursor pollutants nitrogen oxides (NOx) and reactive organic compounds (ROC), in the presence of sunlight. Ozone is a strong irritant that adversely affects human health and damages crops and other environmental resources. Both short-term and long-term exposure to ozone can irritate and damage the human respiratory system, resulting in:

- Decreased lung function,
- Development and aggravation of asthma,
- Increased risk of cardiovascular problems such as heart attacks and strokes,
- Increased hospitalizations and emergency room visits, and
- Premature deaths.

The District is in attainment for most of the Ambient Air Quality Standards. For the federal 8-hour ozone standard that was adopted in 2015, the District's attainment status has not yet been designated by EPA, but it is expected to be attainment.

Pursuant to California Health and Safety Code (H&SC) section 40925.5, the District is currently designated as nonattainment-transitional for the state ozone standard. As required by the California Clean Air Act, the District prepared the 2016 Ozone Plan that included a schedule for implementing control measures to reduce emissions of ozone precursors. H&SC section 40925.5 required the District to review the 2016 Ozone Plan's rule schedule after being designated nonattainment-transitional. The review and revision to the rule schedule were approved by the District Board on August 17, 2017.[2]

[1] Additional information on California's SIP can be found here: https://www.arb.ca.gov/planning/sip/sip.htm
[2] Additional information on the District's change in designation to nonattainment-transitional, and the changes to the 2016 Ozone Plan's control measure implementation schedule, can be found here: https://www.ourair.org/planning-clean-air/

The proposed amendments to Rule 360, which regulate emissions from boilers, water heaters, steam generators, and process heaters, are considered to be a "feasible measure." The rule amendments were identified in both the District's 2013 Clean Air Plan and 2016 Ozone Plan because many other Districts have adopted and implemented similar requirements in the last five years. The District's 2016 Ozone Plan and the revised nonattainment-transitional rule schedule include a commitment to achieve NOx emission reductions from this category of emission units.

Since the District was recently designated as nonattainment-transitional, H&SC section 40930 requires the District to do a cost-benefit analysis and provide a justification before any new control measures are adopted. That analysis is included in Section 5 of this staff report.

3. PROPOSED RULE AMENDMENTS

3.1 Overview of Proposed Amendments

The District is proposing the following major amendments to Rule 360:

- Lowering the NOx emission limit for natural gas-fired units from 55 or 30 ppm down to 20 ppm;[3]
- Adding an exemption for recreational vehicles, manufactured homes, hot water pressure washers, and portable water heaters used for underwater diving activities;
- Requiring units to meet the emission limits of the rule if they are modified; and
- Clarifying the applicable testing requirements.

All of the amendments are described in further detail in their corresponding sections below.

3.2 Rule Title

When Rule 360 was initially adopted in 2002, it was named "Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers." This name, by itself, informs the reader that if you have a boiler or water heater, you should read the rule to learn if there are any applicable requirements to your equipment unit. However, the naming becomes more convoluted when comparing it to other District-adopted boiler and water heater rules, such as:

- Rule 352 – Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters;
- Rule 361 – Small Boilers, Steam Generators, and Process Heaters;
- Rule 342 – Control of Oxides of Nitrogen (NOx) from Boilers, Steam Generators, and Process Heaters.

To minimize the confusion between the various boiler rules, a new naming convention will be used for future amendments to the above-mentioned rules, including Rule 360.

[3] All parts per million by volume (ppm) measurements are expressed on a dry gas basis and corrected to 3% stack gas oxygen.

Proposed Rule 360 will be named "Boilers, Water Heaters, and Process Heaters (0.075 – 2 MMBtu/hr)." This title creates a simplified boiler rule naming convention that conveys the applicability without having to open the rule, which will help the public quickly identify the applicable rule for their equipment unit.

3.3 Exemptions

"Recreational Vehicles" and "Manufactured Homes"

An exemption for units installed in "recreational vehicles" and "manufactured homes" is proposed. These units are typically below the applicability range of 0.075 MMBtu/hr and they do not operate very frequently. The District has noticed that other California air districts, such as the SCAQMD and the Bay Area Air Quality Management District, exempt these units since some models could foreseeably be larger than 0.075 MMBtu/hr and become subject to the rule. The initially adopted Rule 360 was never implemented on these types of units. In the interest of consistency with other air districts, these units are proposed to be exempted from the rule.

"Pressure Washers"

From reviewing neighboring air district rules, it became apparent that "pressure washers" could be considered "water heaters." Pressure washers are used in various industries, including food processing, construction, and transportation industries. The pressure washers are used to clean and degrease machinery, vehicles, work surfaces, and floors. As such, most units are portable and are fired on diesel fuel since it is more readily available and practical for portable uses than natural gas. Since most hot water pressure washers are portable, add-on NOx controls are not feasible. In addition, these units are generally used for short duration projects. Due to the limited use of these types of units, it is not cost-effective to require low-NOx burners. Furthermore, the initially adopted Rule 360 was never implemented on these types of units. In the interest of consistency with other air districts, pressure washers are proposed to be exempted from the rule.

"Water Heaters used for Underwater Diving"

Water heaters are sometimes used to supply heated water to underwater divers as a form of temperature control. The portable heaters are stationed on the surface and they send the water to the diver via insulated pipes in the umbilical line. Due to the portability of these units, they are typically diesel-fired. When the District became aware of these types of units in 2008, an exemption from permit requirements was added to District Rule 202. Since the initially adopted Rule 360 never intended to regulate these portable water heaters, they are proposed to be exempted from Rule 360 as well.

3.4 Definitions

"Modification" or "Modify"

Since the initial adoption of Rule 360, the District has encountered some instances where an operator replaces the burner on an older, higher-emitting unit to extend the useful life of the unit instead of purchasing a new, lower-emitting certified unit. To prevent this from occurring, the

District proposes to add the definition for “modification” or “modify” to Rule 360. Under this definition, any operator who replaces the burner or reinstalls the equipment at a location other than the site of its original location shall comply with the applicable emission limits required by the rule at the time of the modification. This language keeps Rule 360 consistent with the previously adopted Rule 361 and its associated determinations.

Please note that this definition does not impose a new requirement to obtain a permit for the burner modification. Burner modifications already require a permit application in accordance with District Rule 201 unless the action is exempt pursuant to Rule 202. There are only a limited number of cases where an operator would perform a burner modification because the vast majority of Rule 360 units are packaged units that are not subject to District permit requirements.

“Rated Heat Input Capacity”

This definition change is made to keep Rule 360 consistent with the previously adopted Rule 361 and its associated determinations. It provides additional clarity in regards to any unit that may have been derated to make sure that it follows the proper procedures.

“Heat Input”

This definition was added to provide clarification that the District uses the gross Btu measurements, as based on the higher heating value of the fuel.

“ppm”

This definition was added to provide clarification that the parts per million by volume (ppm) emission limits for oxides of nitrogen (NOx) and carbon monoxide (CO) are expressed on a dry gas basis.

3.5 Requirements - Emission Limits

“New Limits - 20 ppm”

The focus of this rule amendment is to lower the existing emission limits to a 20 ppm NOx emission limit. This limit was originally identified by the SCAQMD as a feasible standard in their 2006 rule, which required new units to meet the 20 ppm limit by 2010 or 2012, depending on their size. Since 2006, other air districts across the state have amended their rules to reflect the lower SCAQMD standard, and accordingly, it was identified in the District’s Ozone Plan as a rule amendment that should be pursued.

It is understood that not all fuel types can easily meet the 20 ppm NOx standard. Units that are fired on non-pipeline quality natural gas, such as boilers that are fired on digester gas at a wastewater treatment plant, cannot easily achieve these emission levels. This is mainly due to the fluctuations or impurities in the fuel as well as the lower heat content. These other fuel types have different emission standards in the rule to reflect what is feasible with the available technologies. Hence, no changes are proposed for the emissions limits that apply to non-natural gas units.

The rule would remain as a point-of-sale or attrition rule instead of a forced replacement rule. The new limits are proposed to become effective on January 1, 2019, which gives distributors time to sell or relocate any equipment that does not meet the new emission standards. Prior to January 1, 2019, the previously adopted emission limits, as referenced in Table 1 of the rule, would still apply.

<u>"Pool Heaters"</u>

Pool and spa heaters rated at less than 400,000 Btu/hr are typically used for small residential applications. The District is proposing to maintain the existing NOx emission limit of 55 ppm for these units instead of lowering it to 20 ppm. This is mainly because the cost-effectiveness estimate is quite high for these pool heaters due to the limited number of hours that they operate each year. Furthermore, no other air district has proposed a lower NOx emission limit for small pool heaters. Therefore, no changes to the emission limits for this category are proposed.

3.6 Compliance Certification

New text has been added that allows the SCAQMD certification to be used in lieu of the District's own certification process. The District currently accepts SCAQMD certification for these units since many manufacturers have already obtained a SCAQMD certification and the SCAQMD program was determined to be equivalent to our own. Accordingly, text was added to clarify this option for manufacturers.

3.7 Testing Provisions

Rule 360 also applies to non-natural gas-fired units. However, the test methods in the rule were only focused on the SCAQMD protocol for pipeline quality natural gas-fired units. Hence, the test methods in the rule had to be expanded for the other fuel types. New text has been added that clarifies the standard source test methods and compliance demonstration requirements for all applicable fuel types.

4. COMPARISON WITH OTHER AIR DISTRICTS

The District compared Rule 360 to the following rules in other air districts:

- South Coast Air Quality Management District
  Rule 1146.2 - Emissions of Oxides of Nitrogen From Large Water Heaters and Small Boilers and Process Heaters
- Ventura County Air Pollution Control District
  Rule 74.11.1 - Large Water Heaters and Small Boilers
- San Joaquin Valley Air Pollution Control District
  Rule 4308 - Boilers, Steam Generators, and Process Heaters – 0.075 MMBtu/hr to less than 2.0 MMBtu/hr
- Bay Area Air Quality Management District
  Regulation 9, Rule 6 - Nitrogen Oxides Emissions from Natural Gas-Fired Boilers and Water Heaters
- Sacramento Metropolitan Air Quality Management District
  Rule 414 - Water Heaters, Boilers and Process Heaters Rated Less Than 1,000,000 BTU Per Hour
- Yolo-Solano Air Quality Management District
  Rule 2.37 - Natural Gas-Fired Water Heaters and Small Boilers
- Placer County Air Pollution Control District
  Rule 247 - Natural Gas-Fired Water Heaters, Small Boilers and Process Heaters
- Feather River Air Quality Management District
  Rule 3.23 - Natural Gas-Fired Water Heaters, Small Boilers, and Process Heaters

A comparison of the District's proposed rule to the rules adopted by other nearby air districts is shown below in Table 4.1.[4] Based on the District's analysis, the proposed amended Rule 360 does not require any provisions that are more stringent than what has already been adopted in these other air districts. Furthermore, the emission standards for this rule were written so they are as consistent as possible with other air districts while still adequately acknowledging the specific needs of the region covered by the Santa Barbara County Air Pollution Control District.

[4] The San Luis Obispo Air Pollution Control District does not have a rule that regulates boilers, water heaters, and process heaters in the 0.075 – 2 MMBtu/hr size range.

Table 4-1: Comparison of Nearby Air District Rules on Boilers, Water Heaters, and Process Heaters

RULE DESCRIPTION / DISTRICT Section	Rule Component	SANTA BARBARA APCD Rule 360 (Proposed)	SOUTH COAST AQMD Rule 1146.2 (2006)	VENTURA APCD Rule 74-11-1 (2012)	SAN JOAQUIN VALLEY APCD Rule 4308 (2013)
Applicability	MMBtu/hr rating	0.075 – 2.0	0.075 – 2.0	0.075 – 1.0	0.075 – 2.0
	Fuel Type	All Gas/Liquid/Solid Fuels	Natural Gas	Natural Gas	All Gaseous/Liquid Fuels
	Type of Rule	Point of Sale	Point of Sale + 15 year Phase-out	Point of Sale	Point of Sale
	When are the new limits effective?	2019	2010 - 2012	2013 - 2014	2015
Exemptions	Recreational Vehicles	Yes	Yes	No	Yes
	Manufactured Homes	Yes	No	No	Yes
	Pressure Washers	Yes	No	No	Yes
Emission Limits	Pool Heaters 0.075 – 0.4 MMBtu/hr	55 ppm NOx	55 ppm NOx	55 ppm NOx	55 ppm NOx
	All other units 0.075 – 0.4 MMBtu/hr	20 ppm NOx	20 ppm NOx	20 ppm NOx	20 ppm NOx
	0.4 – 2 MMBtu/hr	20 ppm NOx 400 ppm CO	20 ppm NOx 400 ppm CO	20 ppm NOx 400 ppm CO	20 ppm NOx 400 ppm CO
	Emission Limit units	ppm or ng/J heat output	ppm or ng/J heat output	ppm or ng/J heat output	ppm or lb/MMBtu heat input
Certification	Certifying Agencies	SCAQMD/itself	SCAQMD	SCAQMD/itself	SCAQMD/itself
	Label Required	Yes	Yes	Yes	Yes
Test Methods	Test Methods	SCAQMD method or CARB/EPA methods	SCAQMD method	SCAQMD method or CARB method	SCAQMD method or CARB/EPA methods

5. IMPACTS OF THE PROPOSED RULE

5.1 Emission Impacts

When aggregated, the emissions from all the units subject to Rule 360 represent a substantial portion of the District's emission inventory. However, since most of these units are exempt from the requirements to obtain a District Permit to Operate, we do not have a definitive count of the total number of units in the county. To obtain an approximate inventory of the Rule 360 units, the District is relying on the studies performed by the South Coast Air Quality Management District (SCAQMD) when they adopted their Rule 1146.2. Prior to their rule proceeding, the SCAQMD gathered data from equipment manufacturers and conducted a statistical survey. Since District Rule 360 regulates the same class and size of units as those subject to SCAQMD Rule 1146.2, the District is using the same assumptions to determine the Santa Barbara County inventory.

Using the SCAQMD assumptions, District staff applied the population-to-unit ratios in order to derive the number of units needed to support the human population in the District. For every 350 people, there is one unit in the size range of 0.075 MMBtu/hr to 0.4 MMBtu/hr and for every 750 people, there is one unit in the size range of greater than 0.4 MMBtu/hr to 2.0 MMBtu/hr. Multiplying the county's estimated population of 450,000 people by the population-to-unit ratios, District staff estimated the unit inventory, as shown in the Table 5-1 below.

Table 5-1: Estimated Number of Units in the District based on Population

MMBTU Range	District Population	Population to Unit Ratio	Number of Units
0.075 – 0.4 MMBtu/hr	450,000	350: 1	1,285
0.4 – 2.0 MMBtu/hr	450,000	750: 1	600
		Total Units:	**1,885**

Since this is a point-of-sale rule, the NOx emission reductions from this proposed rule amendment will occur gradually as units are replaced with newer certified units and as new units are purchased for new developments. Heating equipment that meets the 20 ppm NOx emission limit is currently available from local equipment suppliers and some of these units have already been installed in the county. For these types of units, the average life expectancy is anticipated to be 20 years. For this analysis, it is assumed that over the course of the next 20 years, all existing heating equipment subject to this rule will be replaced in a linear fashion, with about 5% replaced per year.

The following additional assumptions were used to calculate the emission inventory and reductions for units subject to Rule 360:

- A capacity factor of 0.22 was used to develop baseline emissions.[5]

[5] Assumption is based on the 2006 SCAQMD staff report for Rule 1146.2 and confirmed by data reported to them in a 2004 Southern California Gas boiler study.

  - The capacity factor represents the fraction of fuel actually burned by the unit in a year compared to the maximum amount of fuel that a unit could use in a year.
- The distribution of heat input ratings was assumed to be uniform throughout the interval covered by the rule.
  - For the smaller units, the average heat input rating was calculated as:
    - (0.075 + 0.4) / 2 = 0.24 MMBtu/hr
  - For the larger units, the average heat input rating was calculated as:
    - (0.4 + 2.0) / 2 = 1.2 MMBtu/hr
- All existing units were assumed to meet the requirements of the current version of Rule 360.
  - This correlates to a NOx emission factor of 30 ppm (0.036 lbs/MMBtu heat input) for larger units and 55 ppm (0.067 lbs/MMBtu heat input) for smaller units.
- All newly installed units were assumed to meet the proposed limit of 20 ppm (0.024 lbs/MMBtu heat input).
- The total number of units in the county was assumed to remain constant over the next 20 years.

Using the assumptions listed above, the total emissions in tons per year (tpy) for the units can be calculated as follows:

tpy = No. of Units * Avg. Rating * Emission Factor * Capacity Factor * (hrs/year) / (lbs/ton)

Both the current emission inventory and the anticipated emission reductions are shown in the two tables below.

Table 5-2: Estimated Emissions from Rule 360 Units

# Units	**Average Rating** (MMBtu/hr)	**Emission Factor** (lb/MMBtu)	**Capacity Factor**	**hours/ year**	**lbs/ton**	**NOx emissions** (tpy)
1,285	0.24	0.067	0.22	8,760	2,000	19.9
600	1.2	0.036	0.22	8,760	2,000	25.0
					Total TPY:	**44.9**

Table 5-3: Estimated Emission Reductions from Rule 360 Units

# Units	**Average Rating** (MMBtu/hr)	**Change in EF** (lb/MMBtu)	**Capacity Factor**	**hours/ year**	**lbs/ton**	**NOx emission reductions** (tpy)
1,285	0.24	(0.067 – 0.024)	0.22	8,760	2,000	12.8
600	1.2	(0.036 – 0.024)	0.22	8,760	2,000	8.3
					Total TPY:	**21.1**

The anticipated emission reductions from this rule amendment were calculated to be 21.1 tons of NOx per year after the rule is fully implemented and all of the older units are replaced.

5.2 Cost-Effectiveness

Health and Safety Code section 40703 requires the District, in the process of the adopting or amending a rule, to consider and make public its findings related to the cost-effectiveness of a control measure. Cost-effectiveness, for rule-making purposes, is calculated by taking the estimated compliance costs of the rule and dividing it by the amount of air pollution reduced.

Estimated compliance costs for a rule can include, but are not limited to, capital equipment costs, engineering design costs, installation costs, and on-going maintenance costs, such as additional labor or fuel. Because the rule is not forcing additional or early replacement of units, the only cost that is expected to vary for units that comply with a 20 ppm NOx emission limit is the capital cost of the equipment. Although newer units typically have a higher thermal efficiency, the District is taking a conservative approach and assuming that there will be no cost savings from using less fuel. Therefore, the cost to comply with this proposed rule amendment consists solely of the price differential between non-compliant and compliant units.

District staff examined what other districts assumed for price differences between units at the proposed 20 ppm standard and units at the current standard to come up with the estimated differential capital costs for 3 different sized units. These 3 units represent the full range of unit sizes that are covered by the rule, and the differential capital costs are shown in the table below:

Table 5-4: Differential Capital Cost per Unit

Unit Size (MMBtu/hr)	**Bay Area AQMD**	**South Coast AQMD**	**San Joaquin Valley APCD**
0.075	$100	$200	$100
0.4	$250	$630	$750
2.0	$500	$2,800	$3,000

After evaluating the numbers used by the other air districts, the values used by the San Joaquin Valley APCD were determined to be the most up-to-date and representative of similar scenarios that would occur in Santa Barbara County. Hence, the San Joaquin Valley numbers were used for this assessment.

Based on a Rule 1146.2 implementation study conducted by the SCAQMD, the average useful life of boilers is approximately 20 years. Some units may need to be replaced sooner, and others could last up to 30 years if they're maintained properly. For the purpose of this assessment, the District assumed that a unit is replaced after 20 years. The costs listed above are assumed to be the additional initial costs that are necessary at the start of the 20 year period.

For cost-effectiveness calculations, the District uses the Levelized Cash Flow (LCF) method. In the LCF method, a capital recovery factor (CRF) is used to transform the capital cost into an equivalent annual cost. The CRF is necessary because the one-time capital expenditure reduces emissions over the entire duration of the project life. Hence, the CRF is a function of the real interest rate and equipment life. The annualized capital equipment cost is calculated using the following formula:

Annualized Cost = Differential Capital Cost * Capital Recovery Factor (CRF)

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1} = \frac{0.06 * (1 + 0.06)^{20}}{(1 + 0.06)^{20} - 1} = 0.087$$

Where:

i = Real Interest Rate (6%)
n = Equipment Life (20 years)

Using the above equation, the annualized costs for each unit are as follows:

Table 5-5: Estimated Annualized Costs per Unit

Unit Size (MMBtu/hr)	**Differential Capital Cost**	**CRF**	**Annualized Cost** ($/yr)
0.075	$100	0.087	$9
0.4	$750	0.087	$65
2.0	$3,000	0.087	$260

The total estimated emission reductions calculated for all of the units in this size category was previously shown as 21.1 tons per year of NOx. However, cost-effectiveness calculations depend on the emission reductions from a single unit. The emission reductions per unit are estimated using the same assumptions and methodology as used in Section 5.1, Emission Impacts.

Table 5-6: Estimated Emission Reductions per Unit

Unit Size (MMBtu/hr)	**Change in EF** (lb/MMBtu)	**Capacity Factor**	**hrs/year**	**lbs/ton**	**NOx emission reductions** (tpy)
0.075	(0.067 – 0.024)	0.22	8,760	2,000	0.0031
0.4	(0.067 – 0.024)	0.22	8,760	2,000	0.0166
2.0	(0.036 – 0.024)	0.22	8,760	2,000	0.0231

For calculating the final cost-effectiveness in dollars per ton, the annualized cost of a unit is divided by one year's worth of the estimated emission reductions for the unit. The final cost-effectiveness values for each unit type are as follows:

Table 5-7: Cost-Effectiveness per Unit

Unit Size (MMBtu/hr)	**Annualized Cost** ($/yr)	**NOx Reductions** (tpy)	**Cost-Effectiveness** ($/ton)
0.075	$9	0.0031	$2,800
0.4	$65	0.0166	$3,900
2.0	$260	0.0231	$11,300

These cost-effectiveness values are conservative estimates as they do not account for the increase in fuel efficiencies from using a newer unit instead of an older unit. Even so, the cost-effectiveness of the rule is within the acceptable range of previously adopted boiler prohibitory rules, and so Rule 360 is considered to be cost-effective.

5.3 Incremental Cost-Effectiveness

H&SC section 40920.6 requires the assessment of incremental cost-effectiveness for a regulation that identifies more than one control option to meet the same emission reduction objectives. The incremental cost-effectiveness is the difference in cost between two successively more effective control strategies, divided by the additional emission reductions achieved for each of the control strategies.

When comparing alternative technologies available for achieving NOx reductions for small boilers, the most cost-effective means is implementing low-NOx burners. Two additional technologies that have been explored for larger-sized boilers are flue gas recirculation (FGR) and selective catalytic reduction (SCR). Flue gas recirculation and selective catalytic reduction are alternatives to low-NOx burners that can provide greater emission reductions, potentially down to 12 ppm. However, the costs involved with these alternatives are 3-5 times higher than the costs of low-NOx burners. Manufacturers have stated that it would be infeasible to require such stringent emissions controls on such small units for the minimal emission decrease.[6]

Additionally, SCR is designed for industrial units that operate under steady, stable conditions and can maintain the temperature that the catalyst requires for NOx reduction. Smaller units that are turned on and off throughout the day cannot maintain the temperatures required to effectively control NOx emissions. Finally, both FGR and SCR systems require frequent maintenance, which is not practical for small service and commercial settings.

For all of these reasons, the proposed NOx emission limit of 20 ppm is considered the lowest certifiable NOx emission limit in practice for this size range of units. However, please note that permitted units that are subject to the Best Available Control Technology (BACT) requirements from District Rule 802, New Source Review, may still be subject to more stringent emissions limits than the proposed limit of 20 ppm in Rule 360. This is because BACT is the most effective emission control technique which has been achieved in practice, and a lower limit, such as 12 ppm, is still achievable despite the additional costs.

5.4 Socioeconomic Impacts

H&SC section 40728.5 requires the Board to consider the socioeconomic impact of any new rule if air quality or emission limits are significantly affected. However, Districts with a population of less than 500,000 persons are not required to do this socioeconomic analysis. Using 2010 census data and the expected growth rates for the County from the Santa Barbara County Association of Governments, the current population of 450,000 is below the 500,000 person threshold. Therefore, the District is not required to consider the socioeconomic impacts of the proposed rule amendment.

[6] Sacramento Metropolitan Air Quality Management District – Staff Report for Rule 414 (Water Heaters, Boilers and Process Heaters Rated Less Than 1,000,000 Btu per Hour), January 15, 2010

5.5 Impact to Industry

Rule 360 is a point-of-sale rule and the source categories affected include boiler and water heater manufacturers, distributors, plumbing wholesalers, and contractors. Since the units affected by the proposed amendments are found throughout the commercial sector, a wide range of businesses and industries may be affected.

The amendment of Rule 360 will have a small fiscal impact on purchasers of new boilers, water heaters, and process heaters. The rule does not require businesses to replace their equipment, but when they choose to replace the equipment, they must purchase the low-NOx units. New equipment meeting the emission limits of proposed Rule 360 costs approximately 5-10% more than equipment with higher emissions. These additional costs were documented in Section 5.2, above.

In some instances, purchasing a new unit may result in cost savings. While the low-NOx equipment costs more, businesses can save on fuel costs by using the newer, more efficient units. Please note that in the cost-effectiveness calculations of this staff report, a conservative approach was used and so it was assumed that there would be no fuel savings.

Because many manufacturers already offer compliant equipment and the incremental cost increase is small in proportion to the total price of a replacement unit, staff concludes that meeting the proposed 20 ppm limit will not significantly impact industry.

5.6 Impact to the District

Since 2008, a District permit has been required for equipment with an input rating of 2 million Btu/hr and greater, or for multiple smaller units feeding the same load where the combined thermal rating adds up to 2 million Btu/hr or greater. Most Rule 360 applicable units are used on their own and so they are exempt from the requirements to obtain a Permit to Operate. There are approximately 1,885 units in the District in the Rule 360 size range. Approximately 220 units are permitted and the estimated 1,665 remaining units are located at facilities that are exempt from permit requirements.

The proposed amendments are not expected to result in any significant increased workload for District staff since the proposed rule will remain at the point-of-sale level and will be implemented by manufacturers, contractors, and retailers. Occasional compliance checks at non-permitted businesses or construction sites may be performed by District staff to verify compliance with the provisions of this rule. Since this is already a part of the District's ongoing compliance program, increases in staff workload are not anticipated due to the amendments. As for the permitted equipment, businesses that operate under a District permit and choose to modify or replace their equipment are assessed an application and permit evaluation fee to cover District costs. These businesses would be subject to District permit requirements regardless of this rule amendment.

5.7 Cost-Benefit Analysis

As discussed in the entirety of Section 5, there are both additional costs to industry and emission reduction benefits from the proposed amendments. The additional costs to industry are within the acceptable range of the previously adopted boiler prohibitory rules, and although we are not able to determine the precise amount of emission reductions needed to achieve attainment for the state 8-hour ozone standard, additional reductions of NOx emissions will help to ensure that the District eventually achieves attainment with the health-based standard and will add a margin of safety towards achieving that goal. Hence, the proposed amendments will satisfy the nonattainment-transitional mandates from the California H&SC.

6. ENVIRONMENTAL IMPACTS – CEQA

6.1 Environmental Impacts

California Public Resources Code section 21159 requires the District to perform an analysis of the reasonably foreseeable environmental impacts of the methods of compliance. The analysis shall take into account a reasonable range of environmental, economic, and technical factors, population and geographic areas, and specific sites.

The analysis must include the following information on the proposed rule:

(1) *An analysis of the reasonably foreseeable environmental impacts of the methods of compliance.*

Rule 360 is a point-of-sale rule, where new, low-NOx units replace obsolete standard units over time. Since units become obsolete at different rates and low-NOx units are expected to become obsolete at the same rate as standard units, no additional waste is expected to appear in landfills. In addition, old water heaters and small boilers are frequently recycled. The new low-NOx units are expected to cause no adverse environmental impacts.

(2) *An analysis of the reasonably foreseeable mitigation measures.*

Since no adverse environmental impacts are expected, no mitigation measures are proposed.

(3) *An analysis of the reasonably foreseeable alternative means of compliance with the rule or regulation.*

No alternatives are proposed. As previously discussed in the staff report, there are a number of manufacturers supplying equipment that complies with the proposed rule. Manufacturers are expected to continue to develop compliant equipment, increasing competition and decreasing costs. The above analysis under Public Resource Code section 21159 further demonstrates that there is no reasonable possibility that the amendment of proposed Rule 360 will have a significant effect on the environment due to unusual circumstances.

6.2 CEQA Requirements

The District prepared a program Environmental Impact Report (EIR) for the 2010 Clean Air Plan that evaluated the potential environmental impacts related to the implementation of several control measures aimed at reducing emissions of both ROC and NOx. The 2010 Clean Air Plan EIR included an analysis of potential impacts related to amendments to Rule 360. The proposed Rule 360 amendments are within the scope of the 2010 Clean Air Plan EIR, and that no additional analysis is required under the California Environmental Quality Act (CEQA). A CEQA determination will be made when the proposed rule amendments are brought to the District Board for adoption. Any subsequent changes to the project description during the public review period will undergo additional environmental review under CEQA if it is determined that the changes are outside the scope of the 2010 Clean Air Plan EIR and its associated addendums.

7. PUBLIC REVIEW

Workshops

The District held a public workshop to present, discuss, and hear comments on the draft rule and draft staff report on November 1, 2017 in Santa Barbara. The draft rule and draft staff report were made available on the District's website prior to the public workshop, and there was a two-week comment period after the public workshop. A public notice was placed in the Santa Barbara News Press on October 2, 2017 to notify the public about this event and to encourage participation in the public process. Also, the public notice was distributed to all permitted facilities that own or operate a boiler, water heater, or process heater, as well as to all the manufacturers listed on the SCAQMD list of certified units. And finally, the public notice was distributed to all stakeholders who signed up to receive rule updates from our website.

Comments received during the workshop and during the commenting period following the workshop were considered and were incorporated into the proposed amendments to Rule 360, as appropriate. The public comments can be found in Attachment B and the District's responses to the comments are in Attachment C.

Community Advisory Council

To facilitate the participation of the regulated community and the public in the development of the District's regulatory program, the District created the Community Advisory Council (CAC). The CAC is comprised of representatives appointed by the District's Board of Directors. Its charter is, among other things, to review proposed changes to the District's Rules and Regulations and make recommendations to the Board of Directors on these changes.

The CAC will meet and discuss the amendments to District Rule 360 on December 13, 2017.

Public Hearing

In accordance with H&SC section 40725, the proposed amendments to Rule 360 will be publicly noticed and made available on the District's website prior to the public hearing. The public will be invited to provide comments prior to the public hearing for the adoption of the proposed rule amendments.

8. REFERENCES

1) South Coast Air Quality Management District – Rule 1146.2 (Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters), Amended May 5, 2006.
2) South Coast Air Quality Management District – *Staff Report for Proposed Amended Rule 1146.2 (Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters)*, April 2006.
3) South Coast Air Quality Management District – Rule 1146.2 (Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters) – List of Certified Units, Updated July 7, 2017.
4) San Joaquin Valley Air Pollution Control District – Rule 4308 (Boilers, Steam Generators, and Process Heaters), Amended November 14, 2013.
5) San Joaquin Valley Air Pollution Control District – *Staff Report for Rule 4308 (Boilers, Steam Generators, and Process Heaters),* October 15, 2013.
6) San Joaquin Valley Air Pollution Control District – *Staff Report for Rule 4308 (Boilers, Steam Generators, and Process Heaters),* November 5, 2009.
7) Ventura County Air Pollution Control District – *Staff Report for Rule 74.11.1 (Large Water Heaters and Small Boilers),* May 10, 2012
8) Sacramento Metropolitan Air Quality Management District – *Staff Report for Rule 414 (Water Heaters, Boilers and Process Heaters Rated Less Than 1,000,000 Btu per Hour),* January 15, 2010
9) Bay Area Air Quality Management District – Regulation 9, Rule 6 (Nitrogen Oxides Emissions From Natural Gas-Fired Boilers and Water Heaters), Amended November 7, 2007.

9. ATTACHMENTS

9.1 Attachment A. FAQs and Rule Clarification

9.2 Attachment B. Public Comments

9.3 Attachment C. Response to Comments

ATTACHMENT A

FAQs and Rule Clarification

FAQs and Rule Clarification

The following text provides rule clarifications in the format of frequently asked questions:

1. **Question:** What types of units are considered "Process Heaters," as defined in the rule?

   Response: Any type of unit where the products of combustion do not come in contact with the process stream. The following types of units are considered process heaters:
   - Heated Process or Storage Tanks
   - Heater Treaters
   - Thermal Fluid Heaters
   - Asphaltic Oil Tank Heaters
   - Glycol Dehydrators
   - Amine Reboilers
   - Absorption Chillers

2. **Question:** What types of units are NOT considered "Process Heaters," as defined in the rule?

   Response: Any type of unit where the products of combustion come in contact with the process stream. The following types of units are not considered process heaters:
   - Afterburners, Flares, Thermal Oxidizers, or Degassing Units
   - Evaporators, Fryers, Metal Heat Treating or Metal Melting Furnaces, Metal Pots, or Tar Pots
   - Ovens, Dryers, Kilns, Calciners, Cookers, or Roasters
   - Crematories or Incinerators
   - Make-Up Air Heaters, such as on a Spray Booth
   - Humidifiers
   - Tenter frame, fabric, or carpet dryers

3. **Question:** Can instantaneous water heaters meet the new 20 ppm limit?

   Response: Yes, instantaneous water heaters can meet the new limit. These types of units had difficulties in reaching the 20 ppm limit because manufacturers used to use partial premix burners. However, manufacturers are now using fully premixed burners or multiple modulating burners to achieve finer control and lower emissions.

4. **Question:** The boiler that my company is proposing to install is listed on the current SCAQMD Rule 1146.2 certification list. However, my company will be firing the boiler on propane instead of natural gas. Does the certification still apply?

Response: Yes, the District will accept the certification for the propane-fired unit as long as the model of the boiler is on the current SCAQMD certification list. The propane-fired unit will be able to meet the “All Other Fuels” emission limits, as shown in Table 2 in Rule 360.

5. **Question:** The boiler that my company is proposing to install is listed on the current SCAQMD Rule 1146.2 certification list. However, my company will be firing the boiler on field gas instead of natural gas. Does the certification still apply?

   Response: Yes, the District will accept the certification for the field gas-fired unit as long as the model of the boiler is on the current SCAQMD certification list. Field gas is collected in the Oil and Gas processing fields and it typically has a Btu content of 900 to 1,250 Btu/scf. Based on the results of District-witnessed source tests, field gas-fired units will be able to meet the “All Other Fuels” emission limits, as shown in Table 2 in Rule 360.

   It is important to note that this determination does not extend to landfill gas or digester gas, as these fuels typically have a Btu content that is much lower than natural gas and field gas.

6. **Question:** The boiler that my company is proposing to install is not on the most recent version of the SCAQMD Rule 1146.2 certification list, but the boiler is on an older version of the certification list. Does the certification still apply?

   Response: No, the old certification does not apply. At the time of installation or modification, the boiler needs to be on the most recent version of the SCAQMD certification list. Alternatively, the manufacturer can follow the procedures in the rule to receive a certification for Santa Barbara County.

7. **Question:** Is there a fee for the application or certification process to have my Rule 360 unit certified with the Santa Barbara County APCD?

   Response: There is no additional fee to submit an application to certify a unit under Rule 360.

8. **Question:** I’m planning on installing two 1.8 MMBtu/hr natural gas-fired boilers together. Are they subject to Rule 360?

   Response: Yes, the boiler rule that applies is determined based on the size of each individual unit. In this scenario, both units would be subject to the Rule 360 standards.

   As for the permitting requirements, that question relates to “stacking,” which is a permitting issue only. If a company installs two 1.8 MMBtu/hr boilers and the system is designed such that both units may be operated concurrently (i.e., the design heat input is greater than 2.0 MMBtu/hr), then a permit is required. If the second unit is solely a backup unit and the design criteria for the system is less than 2.0 MMBtu/hr, then a permit will not be required.

ATTACHMENT B

Public Comments

Timothy J. Mitro

From:	Gong, Kevin <Gong.Kevin@epa.gov>
Sent:	Friday, October 6, 2017 10:35 AM
To:	Timothy J. Mitro
Cc:	Law, Nicole; Lo, Doris
Subject:	RE: Draft Rule 360 submittal - EPA

Dear Timothy,

Thank you for providing us with the opportunity to comment on the draft revisions to Santa Barbara County APCD's Rule 360, dated September 12, 2017. Per our phone discussion yesterday, I am sending in writing our comments that SBCAPCD should consider prior to your pending public workshop.

1. The new draft at (B) exempts water heaters used for underwater diving operations, hot water pressure washers, units installed in manufactured homes, and units used in recreational vehicles. The draft staff report indicates that the first two categories (dive heaters and pressure washers) were never intended for regulation under the original rule. The second two categories (units in manufactured homes and RVs) were previously applicable, but other districts' rules for similar source categories exempt these types of units. The staff report indicates that the District believes the emission contribution from these sources is small, but this new exemption could still constitute backsliding under Clean Air Act section 110(l). Please provide additional analysis on the magnitude of potential foregone emissions with this exemption and why you believe it is consistent with section 110(l), or clarify that the second set of units was never regulated under the existing version of Rule 360, similar to the other two exemptions cited above.
2. The new draft includes provisions under (E) for owner or operator modification of certified units with new, lower-emitting burners to extend the useful life of the unit. However, the language describing certification for units in general does not indicate how modified unit already installed at a site can undergo certification. Existing units must be certified under (D). Please clarify how this rule will address certification for modified units.
3. The new draft at (D)(1) recodifies the existing NOx and CO compliance limits for existing and new applicable units from the existing rule into a new Table 1 that is effective through December 31, 2018, but does not indicate that modified units during this period must also comply with these limits as is described under the new emission limits effective January 1, 2019 in Table 2. Will an owner or operator be able to modify a unit in the district to emit at a rate higher than those listed in Table 1?

Please let us know if you have any questions.

Thank you,

Kevin Gong
Rules Office, Air Division (AIR-4)
U.S. Environmental Protection Agency, Region 9
75 Hawthorne St. San Francisco, CA 94105
(415) 972-3073 | gong.kevin@epa.gov

From: Timothy J. Mitro [mailto:MitroT@sbcapcd.org]
Sent: Friday, September 29, 2017 8:03 AM
To: Steckel, Andrew <Steckel.Andrew@epa.gov>

Cc: Molly M. Pearson <PearsonM@sbcapcd.org>; Ben Ellenberger <EllenbergerC@sbcapcd.org>
Subject: Draft Rule 360 submittal - EPA

Dear Mr. Steckel,

The District is proposing to amend Rule 360 - Boilers, Water Heaters, and Process Heaters (0.075 – 2 MMBtu/hr). Please find attached the draft rule package for this rule amendment. The District plans to have a public workshop on the revised rule on November 1, 2017. Ideally, we would like to reference any EPA comments concerning this project during that workshop.

The rule is currently scheduled for adoption in March 2018. When adopted, the revised rule will be submitted as an update to the State Implementation Plan and the OCS Regulations.

If you have any questions, feel free to contact me.

Timothy Mitro
Air Quality Engineer II
Santa Barbara County APCD
(805) 961-8883
OurAir.org

Bruce Falkenhagen
2275 Corbett Canyon Road
San Luis Obispo, CA 93401
(805) 748-2045

November 8, 2017
Via email, hard copy not to follow

Timothy Mitro
SBAPCD
260 N San Antonio Road; Suite A
Santa Barbara, CA 93110

Re: Draft Rule 360- Small Boilers, Water Heaters, and Process Heaters (0.075-2 MMBTU/hr) Comments

Dear Tim:

Thank you for having the workshop on proposed Rule 360 and allowing public comment. It is appreciated.

As stated in the workshop, I have the following comments on the draft Rule.

1) Definition of "Modify", page 1. I continue to have a problem with the definition of "Modify" in the Rule. Let it be known that I have no problem with the concept that if I have an old, non-certified heater, and if I wanted to change out that burner, it would not be considered as allowable as a "modification" as defined in the Rule 202. The purpose of this Rule is to slowly eliminate those old units. But it just doesn't seem that this is the appropriate place to put this definition.

a) For an old unit, fine. But make the definition be "Replacing a burner or burners on a non-certified unit". This picks up all the older units, but does not catch the now certified units, which has unintended consequences.

b) If I have a new unit, and say it is 2028 and has been in place for 10 years. I see that the burner is starting to decay and decide I want to replace the burner. Under this rule, that action would become a permitted action, meaning that I would need to go through the whole Application/ATC/PTO process, that for a 1.5 MMBTU/hr heater will cost $2,350 in just APCD fees (Application ATC- $395, ATC Fee- $780, Application PTO- $395; PTO Fee- $780). Because the application steps are minor and the application will really have nothing other than my name and address, there will be minimal company costs, but there will be a time cost for the inspection.

The replacement burner may cost $250. So, I would be paying $2,400 in fees for a $250 burner, that once the heater cools down can be installed in thirty minutes. This makes no sense. It makes me **NOT** want to change out the burner, which, if you think about the combustion characteristics to make the low NOx flame, is exactly the opposite of what the APCD should want, since its mission is to improve air quality. Directionally you are financially forcing me to pollute, when, if I can have my operator swap out the burner for nothing, we all get cleaner air.

The argument that I would replace a burner with some different burner is a red herring and would not occur for many reasons. I just have a $35,000 SCAQMD Certified Heater, where the total installed cost will approach $50,000. Now I need to replace the burner. The new <u>exact replacement</u> may cost $250. Take the very extreme case, I get a burner <u>for free</u> by robbing it from some other old unit. Now will I risk destroying a $50,000 (+) piece of equipment to save $250? A resounding "NO". This other free burner will have different burning characteristics that <u>could</u> make hot spots on the tubes, causing a much more expensive repair. The burner <u>may not</u> generate the heat that I need, I would have to go back and replace it again. The burner <u>may not</u> distribute the gas properly under the designed gas inlet pressures, not making enough heat. The burner <u>may not</u> have the exact same hookup connection, requiring me to jury rig some couplings and 90's and other stuff to force fit it, and then it will not be aligned in the proper location to transfer the heat to the tubes as the heater designer intended.

Just too many things that can go wrong to save $250. It just won't be done.

And where should the APCD's concern stop? What about changing the fuel gas regulator? That is more likely and could change the combustion characteristics. What about me moving the gas piping where I replace some straight runs with 90's to access a new fuel gas line? That changes the pressure drop in the line, that could affect the NOx forming characteristics. Maybe putting a windshield up by the stack to keep rain off the unit? It can inhibit air flow. How about changing out the blower to a different type? That would be a big thing.

I counsel the APCD to look at the big picture here. With the large investment in a specialized heater, no one will be swapping out parts to non-spec'd parts because it is a risk that neither an employee will suggest or an owner who paid for it will want to take. Would you take your USA smogged car and change out the $10 carburetor linkage to one that fits a South African jeep puddle jumper to save $10 and risk junking that beautiful operating car and buying a whole new catalytic converter system? No way.

In addition, under the EPA's and SBAPCD's requirements, only if the capital cost of a job exceeds 50% of the complete replacement cost, is it considered to be something that is required to be reviewed and re-permitted, subject to NSR. A burner is one very small part of the heater unit.

Therefore, there is no justification for calling out a burner replacement as a modification that then requires me to get a new permit.

How about this option: If I need to replace the burner, I am required to notify the APCD of the replacement? It could be added in Section E as a new point; something like: "The District shall be notified in writing of any replacement of a burner, blower, or fuel gas regulator of a certified unit within 30 days of the replacement, identifying the make and model of the replacement parts and the date of installation." Then you have it. If I have a Model A10X Fisher regulator and replace it with a Model DG-16 CE Natco regulator, the District will know it, and can check it out if it wishes. If it is materially different, the unit is no longer certified, or needs to be source tested to validate the change, and the operator/salesman is in violation of the Rule if it does not meet the emission limits. Done.

<u>2. "Natural Gas" vs. "Field Gas".</u> I ask that the APCD add clarification that allows field gas and produced gas (collectively here "Field Gas") as an allowable fuel for a certified unit under this Rule and units using Field Gas be handled as if it was using Natural Gas. "Natural Gas" is effectively defined as PUC grade gas. Looking at the Southern California Gas' tariffs and rules, the typical allowable monthly range for fuel gas is between 1000-1200 BTU/scf, gross, dry (from table- Rule 2.B). Note- it also states that the maximum variation may rarely exceed +/- 100 BTU/SCF of these ranges- Rule 2.B, meaning excursions from 900-1300 BTU/scf can be expected. SCG's Rule 2 is attached.

The range is based on where SCG gets its gas supply. Gas coming from New Mexico and West Texas gas fields suppling it's eastern and San Diego purchasers will be on the lower range; gas coming in from Santa Barbara County and the San Joaquin Valley (oil operations that that use gas plants) will be on the higher range. Stripping out the inerts (nitrogen and CO2), (that enter back in via the combustion air) sets the high BTU level.

Referencing back to the Rule 2 range of 9000-1300 BTU/scf, this wide range of BTU content was considered by the SCAQMD when it established its procedures for certification and the concept of a certified approved list. Field Gas varies the same way, but the range may be 850 BTU/scf up to 1,500 SCF.

Heaters at both ends of the spectrum will be using the same physical low NOx unit from the manufacturer, it's not like a manufacturer is going to build-up a specialty unit for one distinct gas analysis for a small one-time sale heater. It will be the same unit. By allowing the fuel to be used to be both PUC grade Natural Gas and Field Gas, just acknowledges this fact, and encourages operators to make earlier changeouts. The APCD states in the FAQ that propane (2,550 BTU/scf) is allowed to be used and handled by the Rule as if it were Natural Gas.

Without the change, the fear of requiring a source test after the operator purchases an expensive unit, gets an ATC, install the unit, and then potentially faced a shutdown situation in the past, no matter how small that risk may be, has been enough to dissuade operators from talking a risk of installing a new low NOx unit. We need to remove that impediment.

I understand the APCD was thinking of just putting the allowance in the FAQ part of the staff report. The problem with this is that it clearly does not state the allowance for anyone to see. In 20 years, an operator must dig back and find a 20-year-old staff report for the proof of allowance. In addition, future management may forget this discussion, not know of the staff report, or understand the logic behind the inclusion and operators will be punished for it. That is why I think it should be in the Rule language.

I do not advocate letting any gas become allowable; it is well known that landfill/sewage gas and manufactured gas will not work that all have very low BTU content, hence I suggest that a lower limit be established of 850 HHV for this application.

To seamlessly include this provision, I suggest that a definition be added that reads as follows:

"Natural Gas" means Natural Gas as defined in Rule 102, along with field gas and produced gas, with all gasses in the range of 850 BTU-1500 BTU/scf determined to be allowable. This modified definition for Natural Gas only applies to this Rule 360."

<u>3. Cost Effectiveness</u>. The staff report states that the incremental cost for a 2.0 MMBTU/hr low NOx unit is $3,000 (SJVUAPCD). If the District does not allow units firing on Field Gas easy use of the SCAQMD compliance list to satisfy this Rule, the cost effectiveness number is way low. In fact, the cost for the Field Gas units jumps to many multiples of this $3,000 cost figure. At the very least, since the use of the approved compliance list is not allowed, and we would have to source test the unit to show compliance with Tables 1 and 2. Under Rule 210.C., APCD source test approval and witnessing fees cost $1,766, along with the operator's cost for the source test of $3,000 to prepare and run the source test, so at a bare minimum, the incremental cost for a 2 MMBTU/hour unit jumps from $3,000 to $7,766. Working into the cost effectiveness, it then goes from $11,300/ton to $29,251/ton {$11,300 * ($7766 / $3000)}. <u>This is just for the source testing</u>, before any equipment modification.

If the unit is a 1.0 MMBTU/hr unit, the capital cost change for the heater would generally be the same at $3,000, the source test cost factor would be the same, but the emission reduction would be 50%

of that stated in the tables. So, for a 1 MMBTU unit, the cost effectiveness goes up to $58,502/ton. Definitely not cost effective.

Throw into either case any equipment changes (need to change a regulator, change a blower speed, etc.) for the exact same BTU gas as the Natural Gas, it easily would add $10,000. And this would be pure speculation that it is necessary, because it is the same gas as the range that the SCAQMD allows for its certified units. This $10,000 adder then changes the cost effectiveness to over $66,000 for the 2 MMBTU/hr unit and $133,000 for a 1 MMBTU/hr unit.

It is because of these potentially high and uneconomic cost effectiveness numbers that the best option to remove these emissions would be to allow, as I suggest in comment 2, to let field and produced gas units be considered Natural Gas for the purposes of this Rule, and as such, be able to use the certified equipment list for replacements.

4. Gross vs. Net BTU Content. In the workshop I asked about the use of the Gross BTU measurement vs. the Net BTU content measurement. My understanding is that when rating mechanical equipment, the Gross BTU measurement is used for internal combustion engines and the Net BTU measurement is used for heaters and process equipment. The reason is as follows:

The Gross measurement is the heat value including the vaporization of the saturated water entrained in combustion air that becomes part of the air::fuel mixture in the carburetor. A small portion, ~10%, of the heat value of the cubic foot of gas 970 BTU/lb-m is used to change the enthalpy (state of the water) from liquid to gas (steam).

The Net measurement is the same heat value but removing that portion of the fuel that is used to vaporize (boil) that water vapor because it is not usable heat to the process. It is a loss of 970 BTU/lb-m in the change of state.

The Gross measurement is used in rating IC engines, because in that change of state process, the water turning to steam expands 1600-fold. So, it acts, in a piston cylinder, as part of the explosion and some usable work is obtained from that expansion.

The Net measurement is used for boilers and heaters because that process of changing state and its resultant expansion, does not produce any usable heat for the process. The expansion is just lost lost up the stack as steam at atmospheric pressure.

So, to be technically correct, when this Rule speaks to BTU content of the gas, it should be using the Net BTU measurement to determine SCF volumes and rates. However, this will add a higher and confusing degree of complexity to the APCD and industry's compliance with the Rules. Therefore, I suggest that a short section be added to the staff report addressing this correction, but following up with the rationale that this is being done for simplicity for all of the SBAPCD's actions. Just state that the APCD will use the Gross, dry BTU measurement from test reports for its work.

The reason for this is that when I as an operator get a gas analysis from a lab, it will list the BTU content as "1019 BTU/scf Gross- dry, 1001 Gross- wet, 922 Net- wet, 906 Net dry" (Enos, 2015 gas analysis). For those not knowledgeable about enthalpies, they need guidance from the APCD of what to use. That guidance has never been given. If I want to reduce my fees, I will use the Net- dry figure, but that would be incorrect for gas engines.

In my mind, the best way to do this would be to modify the BTU definition to something like; "BTU means British Thermal Unit or units. For the purposes of this Rule, the Gross dry BTU test measurement shall be used for this figure."

If you have any questions please contact me at the number on the first page.

Sincerely,

Bruce Falkenhagen
Attachment

Rule No. 02 Sheet 1

DESCRIPTION OF SERVICE

A. Natural Gas Served

The gas supplied by this Utility is natural gas that is obtained from various sources, primarily oil and gas fields, but also includes landfills and other biomass processes. The gas may consist of any combustible gas or gases so produced. The gas is processed to remove condensible constituents, to minimize the concentration of certain impurities as specified by orders of the California Public Utilities Commission and to add a warning Odorant as defined in Rule No. 1 (gas and Odorant referred to as "gas supplied"). Customers using gas supplied by this Utility for processes which are affected by impurities in excess of specified minimum levels are responsible for testing gas supplied and for rendering the gas suitable for their intended uses. Customers using gas supplied by this Utility should also take reasonable steps to prevent Odorant Fade, as defined in Rule No. 1, that may result in Consumer Equipment, as defined in Rule No. 1. This requirement does not apply to Odorant Fade occurring upstream of Consumer Equipment. N N | | N

EXCEPT AS PROVIDED IN THIS RULE, THE UTILITY MAKES NO WARRANTIES AS TO THE NATURE, COMPOSITION OR PROPERTIES OF THE NATURAL GAS SUPPLIED AND THE OBLIGATIONS SET FORTH IN THIS RULE ARE EXCLUSIVE AND IN LIEU OF ALL OTHER WARRANTIES, GUARANTIES OR LIABILITIES, EXPRESS OR IMPLIED, ARISING BY LAW OR OTHERWISE (INCLUDING WITHOUT LIMITATION ANY OBLIGATIONS OF THE UTILITY WITH RESPECT TO FITNESS, MERCHANTABILITY, CONSEQUENTIAL DAMAGES, AND WARNINGS INCLUDING THOSE RELATED TO ODORANT FADE IN CONSUMER EQUIPMENT). T N N

B. Heating Value of Gas Served

The heating value of the natural gas served will vary from time to time and from place to place depending upon the supplies being drawn and the relative quantities being taken therefrom. The monthly average heating values (in Btu per cubic foot, dry basis, at normal atmospheric pressure of 30" mercury and a temperature of 60 degrees Fahrenheit) of the gas served in the major portion of the Utility's service area are within the range of 1000-1060 Btu, and the maximum variation will rarely exceed 100 Btu above or below this range. The following table shows the typical range of monthly average heating values in each area:

L

(Continued)

Rule No. 02
DESCRIPTION OF SERVICE

(Continued)

B. Heating Value of Gas Served (Continued) L

Area	Range of Monthly Average Btu
Los Angeles Basin	1000-1060
Antelope Valley	1000-1040
Eastern and Inland Area	1000-1040
San Joaquin Valley Area	1000-1180
Ventura County	1010-1130
San Luis Obispo County and Western Santa Barbara County	1030-1130
Santa Barbara County (excluding western portion)	1070-1200
Orange County	1000-1020

L

C. Pressure

The standard delivery pressure at the point of delivery is eight inches of water column.

For connected loads of one million Btu/hour or greater, the following delivery pressures can be provided upon request and acceptance by the Utility:

1. Two Pounds.

2. Five Pounds.

3. Service at as-available fluctuating pressures from the point of service.

4. Such other pressure as the Utility and the Customer agree to.

D. Continuity of Service

Service is continuous, subject to the limitations specifically set forth in the various tariff schedules.

L

(Continued)

Rule No. 02

DESCRIPTION OF SERVICE

(Continued)

E. Determination of Cubic Foot with Displacement Meters L

In cases where gas is metered to customers at the standard delivery pressure described in Section C hereof, a cubic foot of gas shall be construed to be that quantity of gas which, at the temperature and pressure existing in the meter, occupies one cubic foot. Where gas is metered to customers through displacement meters at a pressure higher than that in Section C hereof, a cubic foot of gas shall be construed to be that quantity of gas which, at the temperature existing in the meter and an absolute pressure of 14.73 pounds per square inch, occupies one cubic foot.

F. Determination of Cubic Foot with Other Than Displacement Meters

In cases where gas is metered to customers through other than displacement meters, a cubic foot of gas shall be construed to be that quantity of gas which, at a temperature of 60 degrees Fahrenheit and an absolute pressure of 14.73 pounds per square inch, occupies one cubic foot.

G. Orifice Meter Standards

Utility shall own, operate and maintain devices and related instrumentation to measure gas-flow at each point of receipt and each point of delivery. Utility may elect not to install redundant measurement facilities at interstate pipeline and utility receipt points as long as the supplying pipeline or utility complies with the following measurement standards. Orifice meters shall be installed in compliance with the American National Standards Institute Report ANSI/API 2350. Other types of measuring devices shall be installed in compliance with the manufacturers' recommended specifications and all applicable American Gas Association and American National Standards Institute standards. L

H. Statement to Customers

The Utility shall periodically render a statement to all customers of the calculated amount of gas delivered and measured as hereinbefore provided. It is agreed that such statement shall be accepted (subject to correction for any error in reading meters, charts, gauges or other accessories, or in computation) by both parties as a correct measurement and statement of the amount of gas delivered and to be paid for unless objected to by one party or the other within 15 days from the time of the rendering of such statement.

See Rule No. 16 for information on billing corrections due to meter error.

L

(Continued)

Rule No. 02 Sheet 4
DESCRIPTION OF SERVICE

(Continued)

I. Adjustment for Altitude for Standard Delivery Pressure L

In cases where gas is metered at standard delivery pressure, the metered volume shall be adjusted by the appropriate altitude factor from the following table which corrects for standard delivery pressure and altitude:

Altitude Zone	Altitude Range (Ft.)	Altitude Factor
0	Below 1,000	1.000
1	1,000-1,999	.968
2	2,000-2,999	.935
3	3,000-3,999	.903
4	4,000-4,999	.871
5	5,000-5,999	.841
6	6,000-6,999	.812
7	7,000-7,999	.782
8	8,000-8,999	.755

J. Adjustment for Elevation for Pressure Higher Than Standard Delivery Pressure

In cases where gas is metered to customers through positive displacement meters at a pressure higher than the standard delivery pressure (8 inch), the metered volume shall be corrected, at the temperature existing in the meter, to a standard pressure of 14.73 pounds per square inch absolute. The Utility shall, as appropriate, correct for deviation from Boyle's Law. In correcting the metered gas volume to the standard pressure, the barometric pressure assumed to exist at the meter for various elevation zones shall be taken from the following table: L

(Continued)

Rule No. 02 T
DESCRIPTION OF SERVICE

(Continued)

J. Adjustment for Elevation for Pressure Higher Than Standard Delivery Pressure (Continued)

Standard Average Barometric Pressures of Various Elevation Zones
for Use with High Pressure Gas Displacement Meters

Elevation Zone	Elevation Limits Between Which Standard Barometric Pressure Is to be Used (Feet)	Standard Barometric Pressure (Lbs. per Sq. Inch Absol.)
1	-200-199	14.73
2	200-599	14.53
3	600-999	14.32
4	1,000-1,399	14.12
5	1,400-1,799	13.92
6	1,800-2,199	13.72
7	2,200-2,599	13.53
8	2,600-2,999	13.33
9	3,000-3,399	13.14
10	3,400-3,799	12.96
11	3,800-4,199	12.77
12	4,200-4,599	12.59
13	4,600-4,999	12.41
14	5,000-5,399	12.23
15	5,400-5,799	12.06
16	5,800-6,199	11.89
17	6,200-6,599	11.72
18	6,600-6,999	11.55
19	7,000-7,399	11.39
20	7,400-7,799	11.22
21	7,800-8,199	11.06

K. Conversion of Metered Volumes to Therms for Billing Other Than Utility Electric Generation and Wholesale Customers

The number of therms to be billed shall be the product of the metered volume in Ccf times the billing factor. The billing factor is equal to the applicable Btu factor for the Btu district times the factors for altitude and metering pressure, as appropriate.

(Continued)

Rule No. 02 Sheet 6 T
DESCRIPTION OF SERVICE

(Continued)

K. Conversion of Metered Volumes to Therms for Billing Other Than Utility Electric Generation and Wholesale Customers (Continued)

The Btu factor for each Btu district will be determined monthly by dividing the average heating value of deliveries to that Btu district by 1,000. The average heating value in the Btu district is based upon the 4-week period ending on the second Tuesday of a 4-Tuesday month, or the 5-week period ending on the third Tuesday of a 5-Tuesday month. This Btu factor shall be used for all billing cycles of the next revenue month.

Where the Utility has a meter device that automatically gathers and records daily or more frequent consumption information, the Utility may apply appropriate district daily or more frequent heating values in determining the customer’s bill, rather than a monthly average heating value.

L. Conversion of Metered Volumes for Billing of Utility Electric Generation and Wholesale Customers

The number of therms to be billed shall be the product of the metered volume in Mcf delivered during each billing period for each service location times the conversion factor. The conversion factor will be determined monthly by dividing the average heating value in Btu per cubic foot (dry basis) for each service location by 100. The metered Mcf of gas delivered during each billing period is determined in accordance with other provisions of Rule 2.

M. The Utility reserves the right to refuse gas service to:

1. Any customer whose fuel requirements impose demands only at times which are coincidental with the period of extreme seasonal peak demands on the Utility's system.

2. Any premises for standby purposes. Utility will notify the Commission whenever a denial of service is contemplated.

N. Standby Service to Bypass Customers

1. A Bypass customer will be put on standby service if it meets the conditions specified in Rule No. 1 for standby service.

2. To the extent a Bypass customer requests a new service line or meter from the Utility for standby service as defined in Rule No. 1, the Utility will install the service line or meter at the customer’s expense. The customer will be subject to a usage evaluation if it uses no transportation service from the Utility for any consecutive 24-month period.

(Continued)

O. Special Facilities

1. Request for Special Facilities. Utility will normally install only those permanent facilities needed to provide standard service pursuant to Rule No. 20, Gas Main Extensions and/or Rule No. 21, Gas Service Extensions. An Applicant for new permanent service or a customer receiving permanent service may request Utility to install special facilities that result in additional cost to Utility over normally installed permanent facilities. If Utility agrees to such installation, Applicant will pay to Utility all costs above Utility's estimated site-specific cost to install, own, maintain, operate and replace permanent, standard facilities, in addition to any other applicable charges pursuant to Utility's tariffs.

2. Special Facilities. Special facilities may be provided to an Applicant for permanent natural gas service or existing customer for permanent natural gas service, and include:

   a. augmented or new facilities which are in addition to, or substitution for, permanent facilities Utility normally installs to provide standard service under its tariffs; or,

   b. existing facilities dedicated in whole or part for the sole use of Applicant. Utility will install, own and maintain special facilities, or dedicate existing facilities as an accommodation to the Applicant, only when acceptable to Utility such that Utility retains operational control and can assure reliability of service to Utility's other customers.

3. Costs Charged to Applicant for Special Facilities.

   a. New Facilities. New facilities that the Utility agrees to install for Applicant's use as special facilities will be installed at Applicant's expense. Applicant will advance to Utility the additional estimated installed cost of the special facilities above Utility's standard facilities. Utility, at its option, may provide Applicant with alternate payment arrangement for installation of new facilities.

   b. Existing Facilities. Utility's agreement to dedicate existing facilities for Applicant's use as special facilities will be at Applicant's expense. Applicant will pay Utility the applicable portion of the estimated installed cost of the existing facilities dedicated to Applicant.

O. Special Facilities (Continued)

3. Costs Charged to Applicant for Special Facilities. (Continued)

c. Ownership Charge. In addition to providing for the payment of charges under any other applicable tariff, the Applicant will pay ownership charge or charges for either Utility-financed or Customer-financed facilities. The monthly ownership charge for Utility-financed facilities includes depreciation, authorized return, income taxes, property taxes, Operation and Maintenance (O&M) expense, Administrative and General (A&G) expense, Franchise Fees and Uncollectibles (FF&U), property insurance and replacement, if needed, for 60 years at no additional cost to the customer. The monthly ownership charge for Customer-financed facilities includes property taxes, Operation and Maintenance (O&M) expense, Administrative and General (A&G) expense, Franchise Fees and Uncollectibles (FF&U), property insurance and replacement, if needed, for 60 years at no additional cost to the customer. At Utility’s discretion, dependent on such factors as the Applicant’s creditworthiness, longevity of the project, practicality of collecting periodic payments, administration of the contract and other factors, Utility may require Applicant to pay the monthly Utility-financed or Customer-financed charge, or a lump sum payment, or Utility may agree to other payment arrangements.

(1) Monthly Ownership Charge. At the Utility's option, the Applicant will be required to pay monthly Utility-financed or Customer-financed ownership charges, as follows:

Type of Facility	Financing	Monthly Charge	
Distribution	Customer	0.37% of the amount advanced	I
	Utility	1.24% of the additional cost	I

These monthly ownership charges will commence when the special facilities are first ready to serve, as determined by Utility. Utility will notify Customer of this date, through its first invoice. The monthly ownership charges to Customer will automatically change in the event the rates set forth in this Rule 2 change.

(2) Lump-Sum Payment. At Utility's option, the Applicant may be required to make an equivalent one-time payment in lieu of the monthly charge. The one-time payment will equal the estimated cost of the special facilities, plus the estimated cost of removal or abandonment less the estimated net salvage value of removed or abandoned materials. This payment will be required in the event that the Applicant terminates the use of the special facilities at any time within five (5) years immediately following the date the special facilities are first ready to serve.

(Continued)

O. Special Facilities (Continued)

3. Costs Charged to Applicant for Special Facilities. (Continued)

c. Ownership Charge. (Continued)

(3) Periodic Review. Utility will periodically review the factors it uses to determine the monthly ownership charges stated in this section of this rule. If such review results in a change of more than five percent (5%), the Utility will submit a tariff revision proposal to the Commission for review and approval. Such proposed changes will be submitted no sooner than six (6) months after the last revision.

4. Contracts for Special Facilities. Applicant requesting special facilities will be required to execute a written contract prior to Utility performing its work to install or dedicate special facilities. The general form of such contract shall be on file with the Commission.

ATTACHMENT C

Response to Comments

EPA comments, dated 10/6/2017:

#	Description	Comment	District Response
1	Staff Report	The new draft at (B) exempts water heaters used for underwater diving operations, hot water pressure washers, units installed in manufactured homes, and units used in recreational vehicles. The draft staff report indicates that the first two categories (dive heaters and pressure washers) were never intended for regulation under the original rule. The second two categories (units in manufactured homes and RVs) were previously applicable, but other districts' rules for similar source categories exempt these types of units. The staff report indicates that the District believes the emission contribution from these sources is small, but this new exemption could still constitute backsliding under Clean Air Act section 110(l). Please provide additional analysis on the magnitude of potential foregone emissions with this exemption and why you believe it is consistent with section 110(l), or clarify that the second set of units was never regulated under the existing version of Rule 360, similar to the other two exemptions cited above.	We have clarified in the Staff Report that manufactured homes and RVs were never regulated under the existing version of Rule 360.
2	Section E - Certification	The new draft includes provisions under (E) for owner or operator modification of certified units with new, lower-emitting burners to extend the useful life of the unit. However, the language describing certification for units in general does not indicate how modified unit already installed at a site can undergo certification. Existing units must be certified under (D). Please clarify how this rule will address certification for modified units.	Section E.1 of Rule 360 allows a modified unit to be source tested in place to meet the certification requirement and demonstrate compliance with the emission limits listed in Section D of the rule. Units would have to be tested in accordance with the Test Methods listed in Section G. The District has historically used this procedure to certify units that were not on the SCAQMD certification list.
3	Section D - Requirements	The new draft at (D)(1) recodifies the existing NOx and CO compliance limits for existing and new applicable units from the existing rule into a new Table 1 that is effective through December 31, 2018, but does not indicate that modified units during this period must also comply with these limits as is described under the new emission limits effective January 1, 2019 in Table 2. Will an owner or operator be able to modify a unit in the district to emit at a rate higher than those listed in Table 1?	Prior to January 1, 2019, an operator may still modify a unit that was manufactured prior to October 18, 2003 and not have to comply with the emission limits in Table 1. This is the District's existing compliance determination because Rule 360 (as adopted in 2002) applies to "new units" only.

Bruce Falkenhagen comments, dated 11/8/2017:

#	Description	Paraphrased Comment	District Response
1	Section C - Definitions	I continue to have a problem with the definition of "Modify" in the Rule. Let it be known that I have no problem with the concept that if I have an old, non-certified heater, and if I wanted to change out that burner, it would not be considered as allowable as a "modification". [For example,] if I have a new unit, and say it is 2028 and has been in place for 10 years. I see that the burner is starting to decay and decide I want to replace the burner. Under this rule, that action ("modify") would become a permitted action, meaning that I would need to go through the whole Application/ATC/PTO process, that for a 1.5 MMBTU/hr heater will cost $2,350 in just APCD fees. Make the ("modify") definition be "Replacing a burner or burners on a non-certified unit." This picks up all the older units, but does not catch the now certified units. The argument that I would replace a [certified] burner with some different [model] burner is a red herring and would not occur for many reasons, [as it could] have different burning characteristics that could make hot spots on the tubes, causing a much more expensive repair. Or how about this option: If I need to replace the burner, I am required to notify the APCD of the replacement? It could be added in Section E. And where should the APCD's concern stop? What about changing the fuel gas regulator? In addition, under the EPA's and SBAPCD's requirements, only if the capital cost of a job exceeds 50% of the complete replacement cost, is it considered to be something that is required to be reviewed and re-permitted, subject to NSR. A burner is one very small part of the heater unit.	The specific definition of "modify" in Rule 360 has no bearing on what requires a permit in accordance with Rule 201, Permits Required. The intent of the Rule 360 definition of "modify" is to make sure that any time a burner is changed or modified on or after January 1, 2019, the unit has to meet the new emission limits in Rule 360. The requirement to obtain a permit is contained in Rule 201, and is not being changed by this rule revision. If an operator is unsure of whether a specific action requires a permit, they should contact the District's Engineering Division.

<u>Bruce Falkenhagen comments, dated 11/8/2017:</u>

#	Description	Paraphrased Comment	District Response
2	Section E - Certification	I ask that the APCD add clarification that allows field gas and produced gas (collectively here “Field Gas”) as an allowable fuel for a certified unit under this Rule and units using Field Gas be handled as if it was using Natural Gas. I understand the APCD was thinking of just putting the allowance in the FAQ part of the staff report. The problem with this is that it clearly does not state the allowance for anyone to see. In addition, future management may forget this discussion, not know of the staff report, or understand the logic behind the inclusion and operators will be punished for it. That is why I think it should be in the Rule language. I do not advocate letting any gas become allowable; it is well known that landfill/sewage gas and manufactured gas will not work that all have very low BTU content, hence I suggest that a lower limit be established of 850 HHV for this application.	In response to this comment, the District has added language (as seen below in bold) to Section E.2 of the rule “E.2. In lieu of the requirements of Section E.1, equipment models certified by the South Coast Air Quality Management District in accordance with the requirements of South Coast Air Quality Management District Rule 1146.2, as amended May 5, 2006, shall be considered certified for sale or installation in Santa Barbara County. **The certification shall still be considered valid if the unit is fired on propane or field gas.”** As noted in your comment, field gas can encompass a larger range in the Btu content of the fuel as compared to pipeline quality fuel. The District feels it is appropriate to clarify the typical specifications of field gas in the FAQ rather than having a set limit in the rule. The District agrees that the SCAQMD certification process is not appropriate for very low heating value gases such as landfill gas and digester gas.
3	Cost-Effectiveness	If the District does not allow units fired on Field Gas easy use of the SCAQMD compliance list to satisfy this Rule, the cost effectiveness number is way low. We would have to source test the unit to show compliance with Tables 1 and 2.	As noted in Comment #2 above, the District has clarified in the rule language that the District will accept SCAQMD certified units that are fired on field gas. As far as the cost-effectiveness calculations, these calculations are only looking at the incremental changes of this rule amendment. The requirement to install a certified unit (or source test the unit if it isn’t on the SCAQMD certified list) is an existing requirement in the 2002 version of Rule 360, and so the original costs aren’t evaluated in this rule amendment. Furthermore, we expect the majority of operators to purchase new, certified units, leaving a very small number of operators that may still be required to source test.

Bruce Falkenhagen comments, dated 11/8/2017:

#	Description	Paraphrased Comment	District Response
4	Section C - Definitions	The definition of max heat input rating requires additional clarification (are we referring to “gross” or “net”? “Wet” or “dry”? Therefore, I suggest that a short section be added to the staff report to state that the APCD will use the Gross, dry BTU measurements, but following up with the rationale that this is being done for simplicity for all of the SBAPCD’s actions.	The District agrees that the max heat input rating is based on the gross Btu measurements of the fuel. To clarify this in the rule, the District has added the definition of “Heat Input,” which is defined as follows: **“Heat Input”** means **t**he heat of combustion released by fuels burned in a unit based on the higher heating value of the fuel. This does not include the enthalpy of incoming combustion air. This definition works in tandem with the definition of Higher Heating Value (HHV), which is defined in Rule 102 as follows: **“Higher Heating Value”** means the total heat liberated per mass of fuel burned (British thermal unit per pound), when fuel and dry air at standard conditions undergo complete combustion and all resulting products are brought to their standard states at standard conditions. “Gross heating value” shall have the same meaning as “higher heating value.”