MARATHON

Tesoro Refining & Marketing Company LLC
A subsidiary of Marathon Petroleum Corporation

Los Angeles Refinery – Carson Operations
2350 E. 223rd Street
Carson, California 90810
310-816-8100

February 1, 2021

VIA Certified Mail and eMail (*wnastri@aqmd.gov*)
Return Receipt Requested

Wayne Nastri
Executive Officer
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Re: Second Set of Comments on SCAQMD Revised Draft of Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (Release Date: December 24, 2020)

Dear Mr. Nastri:

On behalf of Tesoro Refining & Marketing Company LLC, a wholly owned subsidiary of Marathon Petroleum Corporation (collectively, "MPC"), MPC appreciates this opportunity to provide South Coast Air Quality Management District (SCAQMD) with additional comments on the Revised Preliminary Draft Proposed Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Industries (Proposed Rule 1109.1) that was issued on December 24, 2020.[1] Throughout the rulemaking process, MPC staff continues to be active participants in Proposed Rule 1109.1 working group meetings and discussions with SCAQMD staff.

This set of comments supplement MPC's comments submitted to SCAQMD on December 22, 2020 and provide additional detail on key issues concerning the technical feasibility, safety, and cost of NOx emissions controls for BARCT.[2]

Through this letter, MPC provides supplemental comments further explaining the key issues that SCAQMD must consider with the technical feasibility, safety, and costs necessary to comply with the rule as currently proposed. This examination is centered on the 2 ppm NOx (at 3% oxygen and 5 ppm ammonia slip) emissions limit in Table 1 for boilers and process heaters with a rated heat input capacity of at least 40 million British thermal units per hour (MMBtu/hr). However, many of the fundamental issues described herein apply also to other source categories covered in Proposed Rule 1109.1.

---

[1] SCAQMD, "Revised Preliminary Draft Proposed Rule 1109.1", http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/r1109-1-rule-language---12-24-20.pdf

[2] Correspondence from Brad Levi of Marathon Petroleum Company to Phillip Fine of SCAQMD, December 22, 2020.

In support of this review, MPC retained Mr. L. David Wilson of EN Engineering, LLC to conduct technical feasibility analyses to meet the NOx emissions limits in Proposed Rule 1109.1 for refinery heaters. Please refer to Attachment A for a professional profile of Mr. Wilson's four decades of direct experience with the design and operation of refinery fired equipment. Attachment B is a paper providing key NOx emissions control retrofit considerations for existing refinery process heaters.

Mr. Wilson was also commissioned to complete a technical review of corresponding studies recently completed by Norton Engineering Consultants ("NEC report") and Fossil Energy Research Corporation ("FERCo report") that were commissioned by SCAQMD to assist staff's BARCT assessment.[3] Attachment C outlines our fundamental concerns with the NEC and FERCo reports that may lead to inappropriate conclusions for BARCT.

Background and Overview

Proposed Rule 1109.1 is being developed as a result of SCAQMD's planned transition from the Regional Clean Air Incentives Market (RECLAIM) program to a command-and-control regulatory structure for achieving BARCT. MPC's Los Angeles Refinery (LAR) has been complying with the RECLAIM market-based NOx emission reduction program since 1993. As noted in our prior comment letter, Proposed Rule 1109.1 will be the most wide-reaching, complex, and costly refining industry rule ever developed by SCAQMD. It will cover at least seventy-six (76) distinct pieces of equipment at LAR alone. As presently drafted, it applies a one-size-fits-all approach that calls for installation of ultra-low NOx burners (ULNBs) and selective catalytic reduction (SCR) on the majority of this equipment. MPC has preliminarily concluded that NOx emissions controls and infrastructure needed to comply at LAR cannot be retrofitted at more than half of the existing heaters and boilers due to inherent physical and safety constraints without significant rebuild and/or replacement. A requirement that cannot be implemented in *most* cases is patently inconsistent with applicable state law, which requires BARCT limits to be actually "achievable." Health and Safety Code § 40406.

BARCT limits applied by SCAQMD must also account for economic impacts and meet cost-effectiveness requirements. *Id.* §§ 40406, 40920.6(a). Proposed Rule 1109.1 violates these requirements. The cost-effectiveness analysis on which it is based is deeply flawed, relying on superficial generalizations that do not bear out as applied. The analysis fails to include significant unit-specific retrofit and replacement expenses that will be incurred under the current proposal and costs for installing best available control technology (BACT) emission controls that will be consequently needed to address resulting particulate matter increases.

Proposed Rule 1109.1 is also inconsistent with the requirements of Assembly Bill (AB) 617, which contemplates application of BARCT limits in a manner that achieves actual air quality benefits to the surrounding community. *Id.* § 40920.6(d). The requirements embodied in Proposed Rule 1109.1 appear to ultimately do the opposite, as they will achieve minimal impacts on total NOx emissions in the Los Angeles Basin and will potentially increase particulate matter (PM_{10} and $PM_{2.5}$) emissions by up to approximately 620 pounds per day (or 113 tons per year) from just implementing the proposed rule at LAR alone.

[3] Norton Engineering Consultants, "NOx BARCT Analysis Review", December 4, 2020. Accessed at http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/norton-report.pdf?sfvrsn=6 in December 2020; Fossil Energy Research Corporation, "South Coast Air Quality Management District Rule 1109.1 Study Final Report", November 2020. Accessed at http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/ferco-report.pdf?sfvrsn=6 in December 2020.

In summary, SCAQMD's BARCT technology selection and Proposed Rule 1109.1 limits have not been appropriately determined and are not technically feasible for many of the required installations, and in many cases also present unacceptable safety hazards. Inclusive of the technical issues described in Attachment B are the following critical elements that must be considered in BARCT for boilers and process heaters.

Technical Feasibility

1. **The SCAQMD has not considered the specific technical feasibility issues associated with installing the same controls on the broad universe of process heater designs at refineries.**

Proposed Rule 1109.1 establishes BARCT limits that will require ULNBs and SCRs in many circumstances to potentially achieve the emissions limits, while applied uniformly based solely on heater size. What is missing from this flawed logic is the fundamental fact that there can be inherent operational variability experienced by refinery process heaters within one heater size. Process heaters at petroleum refineries are in many cases complex, custom-designed pieces of equipment built to operate within site-specific constraints.

SCAQMD's use of heat release duty (also referred herein as "size") as the only category to define BARCT for the wide variety of refinery boiler and process heater designs disregards basic physical design characteristics that are mandatory to assess the retrofit feasibility, safety, and performance of new NOx emissions controls. These emissions controls include the combination of ULNBs and SCRs that will be effectively required by Proposed Rule 1109.1.

Specific to the retrofit feasibility of ULNBs, the following characteristics, at a minimum, must be considered when evaluating if ULNBs can be safely implemented and the corresponding level of emissions performance that may be achieved for the heater's operating envelope. Please refer to Attachment B for additional detail.

Risk of Flame Impingement – Operating with ULNBs results in longer flames compared to conventional burners, which may result in flame impingement on internal surfaces such as heater tubes, tube hangers, or refractory. Flame impingement is a major safety concern by causing heater tubes to rupture due to metal fatigue. Flame impingement has the potential to also break heater tube hangers, which may cause the process tubes to fail and create further unsafe conditions. Any of these scenarios could lead to an explosion in the firebox. As discussed more in Item #2 below of this letter, a ULNB retrofit is not technically feasible if flame impingement cannot be avoided due to the radiant section's existing fixed geometry, tube configurations, and burner spacing. Certain design criteria have been developed by the American Petroleum Institute (API) to avoid flame impingement and include key parameters such as heater floor flux density, burner-to-burner spacing, burner-to-tube spacing, among others. The design criteria provided by API Standard 560 (Fired Heaters for General Refinery Service)[4] and API Recommended Practice 535 (Burners for Fired Heaters in General Refinery Services)[5] must be followed as unified design standards in order to manage the risk of flame impingement. Similarly, API Standard 538 (Industrial Fired Boilers for General Refinery and Petrochemical Service) provides design criteria for boilers at

[4] *See* API Standard 560, 5th Edition, February 2016, which specifies requirements and gives recommendations for the design, materials, fabrication, inspection, testing, preparation for shipment, and erection of fired heaters, air preheaters (APHs), fans, and burners for general refinery service; *see also* API Standard 560, Proposed 5th Edition, Addendum 1. Addendum 1 approved and submitted for publication.

[5] *See* API Recommended Practice 535, 3rd Edition, May 2014, which provides guidelines for the selection and/or evaluation of burners installed in fired heaters in general refinery services.

refineries.[6] Computational fluid dynamic (CFD) modeling should be conducted for any fired unit prior to the installation of ULNBs to inform conformance with API 560 and corresponding technical feasibility of any retrofit project. MPC has preliminarily concluded that 56% of the refinery heaters and boilers at LAR cannot be safely operated with a ULNB retrofit without significant rebuild and/or replacement.

Air Preheaters – Some refinery heaters and boilers operate in-line equipment to preheat combustion from residual heat produced by the unit in order to improve energy efficiency. Low-level NOx concentrations are rarely achievable for ULNB retrofits to existing heaters that operate with air preheaters. Air preheaters warm the incoming air to improve energy efficiency, save fuel, and reduce greenhouse gas emissions. The consequence, however, is a hotter flame temperature which increases NOx formation. Performance of NOx emissions for a typical commercially available ULNB at a furnace using an air preheater is 40 to 50 ppmvd at 3% O_2, which is SCAQMD's presumed inlet or uncontrolled NOx concentration in its model heater.

Heater Turndown and Variable Heat Input Operation – Although refinery utilization on a throughput (i.e., barrels of production) basis is normally consistently high (notwithstanding present and future volatility in this market or other externalities like a pandemic that affect demand), many refinery process heaters do not operate at consistently high levels of utilization (low turndown). For example, heaters in hydrotreating and desulfurization processes will operate at relatively low utilization (high turndown) for the start-of-run after a turnaround but will then require higher duty utilization as catalyst activity degrades in the reactors towards end-of-run for the process unit prior to maintenance turnaround activities. Additionally, heater duty may normally fluctuate on a day-to-day basis as a result of variable feed compositions and other frequent changes to heat demand. During high turndown and fluctuating heat input duties, the NOx levels on a concentration basis will be higher than burner guarantees and are unlikely to meet stringent NOx standards being proposed.

Dynamic Changes in Fuel Gas Composition – All refineries combust off gas from the refining process, referred to as refinery fuel gas (RFG). RFG composition can change on a moment's notice. For example, hydrogen concentrations can vary significantly based on operating conditions at other refinery process units. During this transient condition, the amount of excess air required for complete combustion of the fuel can drastically increase. Therefore, the combustion process may not have enough time to respond to the change in RFG, which could result in an unsafe sub-stoichiometric firing condition (i.e., insufficient excess oxygen within the heater for complete combustion). This condition must be avoided at all times, hence the need for flexibility with excess air requirements to accommodate unforeseen process changes. These inherent fluctuations in excess air fluctuations result in higher NOx emissions than for combustion units operating on a more stable fuel.

Routine Burner Cleaning During Normal Operation – ULNB burner tips are smaller than conventional burner technology and require periodic cleaning. A refiner will typically use fuel filters/coalescers to minimize plugging of burner tips; however, online maintenance is necessary as they are smaller than conventional burners. Even with proper fuel conditioning, ULNB burner tips can still become plugged, requiring removal of the burner for online maintenance. Burner removal is likely to degrade ULNB performance because air registers for removed burners commonly leak air (also known as "tramp air"). During online maintenance, the other remaining

[6] *See* API Recommended Practice 538, 1st Edition, October 2015 which provides guidelines for the selection and/or evaluation of boiler components, including burners and combustion equipment, in general refinery and petrochemical services.

burners in service must compensate by firing at higher rates, which increases bridgewall oxygen and NOx formation. While burner maintenance may not be a frequent occurrence, this operating scenario must be considered in establishing limits for ULNB installations on natural draft heaters, which constitute most of the refinery heaters at LAR.

In order to demonstrate the infeasibility of retrofitting a heater based on SCAQMD's BARCT determinations, we conducted a technical feasibility evaluation to retrofit an ULNB at one of the existing LAR refinery heaters. The method we used to evaluate the feasibility of ULNB in this study is based on the consensus API Standard 560, Fifth Edition, Addendum 1 for the oil and gas industry that has been developed by subject matter experts across segments to enhance operational safety, environmental protection and sustainability across the refining industry. Based on our analysis, it is technically infeasible and unsafe to retrofit ULNB technology at this heater, failing several of the key design features recommended in API Standard 560 by significant margins, including the ratio of allowable firebox height to tube circle diameter, floor firing density, flame height, burner-to-burner spacing, and burner-to-tube spacing.

Similarly, a post-combustion control such as SCR that is mandated by BARCT has unique site-specific feasibility issues. Not considered by SCAQMD is the fact that an SCR installation requires a significant footprint area. Inherent to the technical feasibility of any retrofit that includes a new SCR system, the available free space at or near the heater must be evaluated in order to determine if it can even physically be accommodated. MPC has also preliminarily concluded that 52% of SCR systems otherwise required by Proposed Rule 1109.1 cannot physically be installed due to space constraints in the existing process units. It is critical that any technology-forcing standard that necessitates installation of post-combustion controls such as SCR must consider such inherent space constraints, either in determining installation is technically infeasible for that heater category or that the costs associated with redesigning, relocating, and rebuilding process equipment and infrastructure are prohibitive under the cost-effectiveness analysis.

2. **Categorizing refinery equipment solely based on heat release duty (burner size) makes it infeasible to achieve the proposed BARCT NOx levels; Proposed Rule 1109.1's BARCT standards must also consider physical characteristics in determining the feasible level of NOx emissions from existing equipment.**

An appropriate classification of refinery heaters and boilers for BARCT must also consider along with heat release duty, at a minimum, the unique design of heaters that can make it technically infeasible for a ULNB retrofit. Additionally, it is imperative that BARCT consider the existing footprint that is available or unavailable for a new SCR system, and the foundational support infrastructure that can become overloaded when heavy SCR equipment is installed vertically due to nearby ground-level plot space being unavailable. As noted in Attachment B, process heaters come in various shapes and sizes, and have been constructed with specific physical features, such as configuration, geometry, and firebox dimensions, and have foundation supports that are fixed at time of original construction. Considerations for retrofit feasibility must include whether the NOx reduction pollution control technology can be accommodated within these constraints.

Key design limits for determining the technical feasibility of ULNB at refinery heaters that need to be considered for categorization under Proposed Rule 1109.1 include, but are not limited to, API Standards 535's and 560's refining industry recognized safe design criteria that are associated with a heater's physical shape (i.e., vertical cylindrical style or cabin or box styles and associated floor-fired burner configurations that may be present). Some of the design criteria in the API standards that should be used for determining technical feasibility of a ULNB retrofit are as follows:

- Vertical Cylindrical:
  - Vertical cylindrical heaters shall be designed with a maximum height-to-diameter ratio of 3.00, where the height is that of the radiant section (inside refractory face) and the diameter is that of the tube circle, both measured in the same units.
  - The minimum clearance from grade to burner plenum or register shall be 2 m (6.5 ft) for floor-fired heaters.
  - The floor heat flux density for floor-mounted burners cannot exceed 300,000 Btu/hr/ft^2.
  - Burner arrangement must meet normalized burner-to-burner and burner-to-coil spacings in equations (5) through (10) of API 560. For vertical cylindrical heaters, the ratio of the burner-circle-diameter (BCD) to the tube-circle-diameter (TCD) shall be designed to satisfy equations (11) through (13) of API 560.
  - The burner flame length design shall not exceed 60% of the radiant section height.
  - The minimum clearance between the flame envelope, as defined in API RP 535, Section 3.22, and unshielded refractory walls shall be 0.50 ft unless it can be shown that refractory service temperature and velocity limits are not exceeded.
- Cabin or Box:
  - For single-fired, box-type, floor-fired heaters with sidewall tubes only, an equivalent height-to-width factor shall be determined by dividing the height of the wall bank (or the straight tube length for vertical tubes) by the distance between wall tube banks and applying the limitations specified in Table 1 of API 560.
  - In cabin and box style heaters, the distance between the unshielded end wall refractory and the nearest burner centerline shall be between 45% and 60% of the burner-to-burner spacing.
  - The minimum clearance from grade to burner plenum or register shall be 2 m (6.5 ft) for floor-fired heaters.
  - The floor heat flux density for floor-mounted burners cannot exceed 300,000 Btu/hr/ft^2.
  - Burner arrangement must meet normalized burner-to-burner and burner-to-coil spacing in equations (5) through (10) of API 560.
  - The burner flame length design shall not exceed 60% of the radiant section height.
  - The minimum clearance between the flame envelope, as defined in API RP 535, Section 3.22, and unshielded refractory walls shall be 0.50 ft unless it can be shown that refractory service temperature and velocity limits are not exceeded.

These and other design limits are critical to reduce the risk of flame impingement and to conform to recognized and accepted good engineering practices. MPC's internal standards for heater design reference API Standards 535 and 560 and also contain additional design limits specific to ULNB installations based on the company's significant experience in this area.

For reference, we have included a flowchart illustrating the steps SCAQMD should take when categorizing process heaters. Please refer to Attachment D. This example is not intended to be inclusive of all the key design criteria that must be considered for feasibility of ULNB and SCR at an existing heater.

3. The SCR performance to the level specified in Proposed Rule 1109.1 is technically infeasible for many refinery heaters.

The technical paper in Attachment B points to several real-world considerations with operating an SCR at refinery heaters that make it infeasible to sustain a long-term performance level of 2 ppm NOx at 3% oxygen with maximum 5 ppm ammonia slip on a 24-hour average. A few of these critical parameters are summarized as follows.

Allowable Ammonia Slip – Achieving the required NOx removal efficiencies on a continuous basis will require a higher level of ammonia slip (i.e. 10 ppmvd), especially for NOx limits with a short-term average compliance period in Proposed Rule 1109.1. There are relatively few operating variables that can be used other than ammonia to manage NOx performance with a fixed bed system like SCR. The ammonia slip limit needs to reflect this accordingly.

CFD Modeling – Even with proper CFD modeling and SCR system design, it is still common for improper mixing to occur initially or over time, resulting in degradation of the NOx removal performance. To meet a 2 ppm limit at 3% oxygen, for example, an SCR vendor will be required to specify an even lower level to account for such intrinsic variabilities. It has not been commercially proven that the 2 ppm limit can be met for the majority of refinery heaters, much less a lower specification. Reasonable tolerances needs to be incorporated in the NOx and ammonia slip limits with respect to both a higher absolute limit and corresponding longer averaging period.

Heater Turndown and Variable Heat Input Operation – Many refinery process heaters do not operate at consistently high levels of utilization (low turndown). For example, heaters in hydrotreating and desulfurization processes will operate at relatively low utilization (high turndown) for the start-of-run after a turnaround but will then require higher duty utilization as catalyst activity degrades in the reactors towards end-of-run for the process unit prior to maintenance turnaround activities. Additionally, heater duty may normally fluctuate on a day-to-day basis as a result of variable feed compositions and other frequent changes to heat demand. These fluctuations will impact SCR performance because the flue gas temperature and inlet NOx entering the reactor correspondingly vacillates, thus lowering the NOx removal efficiency at the SCR system. This needs to be considered for establishing sustained NOx and ammonia slip emissions limits for heaters with SCR.

Unexpected Catalyst Fouling - Although SCR systems are designed to operate at the guaranteed performance at end-of-run operation prior to conducting heater maintenance activities, predicting the actual operating condition of a heater for a several-year period is difficult. For example, it is impossible to predict dust fouling from refractory or heater tube scaling as the materials deteriorate over time. For example, MPC observed the fouling of SCR catalyst on a process heater within just 20 months of operation, reducing the NOx control efficiency by 8% and causing a 9-day unplanned outage. Given this uncertainty, any NOx or ammonia slip limits must be established to allow for compliance during heater operation, up to and including end-of-run operations prior to a process unit turnaround.

As we have explained above, an appropriate evaluation to determine the sustained and consistent performance levels of SCR systems operating in refinery heater service is critical to establishing BARCT. SCAQMD has not considered the fundamental realities that impact SCR performance to meet a 24-hour average NOx standard at a level demonstrated for several years of operation for the wide variety of refinery heater designs. A sustained NOx removal efficiency of 92% for SCR installed at refinery heaters is generally reasonable based on current performance of systems at refinery process heaters and considering real-world operational factors in Attachment B.

Cost Evaluation

California law requires that prior to establishing BARCT requirements, SCAQMD must assess cost-effectiveness of each potential control option. This entails calculating the actual cost, in dollars, of the potential control option. Health and Safety Code § 40920.6(a)(2). It also entails calculating the *incremental* cost-effectiveness of each option to inform the District's BARCT determination. *Id.* § 40920.6(a)(3). This is consistent with the requirement that BARCT itself must be set at an "achievable" level after accounting for "economic impacts." *Id.* § 40406. The current body of evidence assembled by SCAQMD does not satisfy these requirements.

4. The SCAQMD has not considered the incremental cost-effectiveness calculations for Proposed Rule 1109.1 as required under California Health and Safety Code.

Health and Safety Code § 40920.6(a)(3) clearly requires SCAQMD to calculate the incremental cost-effectiveness of technically feasible BARCT options. SCAQMD has conducted such an analysis for other rules and it has been conclusive in its BARCT determination. For example, in the September 2020 draft staff report for the BARCT assessment of NOx emission reductions from combustion equipment at publicly owned treatment works facilities, excerpted below, the SCAQMD demonstrated through its incremental cost analysis that the alternative control option was not viable.[7]

> *Health and Safety Code section 40920.6 requires an incremental cost-effectiveness analysis for Best Available Retrofit Control Technology (BARCT) rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments relative to ozone, carbon monoxide, sulfur oxides, oxides of nitrogen, and their precursors. Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control options as compared to the next less expensive control option.*
> ...
> *The proposed project would require one facility to meet 18.8 ppm at 15 percent oxygen on a dry basis on three turbines. The next progressively more stringent potential control option would be to require turbines to meet 5 ppm at 15 percent oxygen on a dry basis and would affect two facilities and a total of six turbines. To meet 5 ppm, one facility would be required to implement SCR on their existing turbines. The other facility would be required to replace their turbines with lower emitting turbines to meet 5 ppm.*
>
> *Incremental cost-effectiveness = (\$160,832,987 – \$6,712,430) / (1,791 – 138) = \$93,237 per ton of NOx reduced*
>
> *The incremental cost analysis presented above demonstrates that the alternative control option is not viable when compared to the control strategy of the proposed amendments.*

MPC has estimated the average and incremental cost-effectiveness on a high-level for multiple scenarios of presumed technical feasibility for ULNB and SCR. Two examples are provided here to illustrate the impact from SCAQMD failing to take consider the required incremental cost-effectiveness for BARCT. The total capital and operating costs for the control options are engineering estimates and do not take into account lost opportunity cost that may occur due to additional refinery downtime required for compliance (e.g., to extensively overhaul the heater for a ULNB retrofit or to relocate process equipment to accommodate an SCR).

[7] SCAQMD, "Draft Staff Report, Proposed Rule 1179.1 – NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities", September 2020, http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1179.1/pr-1179-1---dsr.pdf

Example 1: Retrofit of ULNB and SCR Assumed to Both be Technically Feasible

Table 1 summarizes the cost-effectiveness for a 200 MMBtu/hr heater at LAR that currently performs at 41 ppmvd NOx at 7.9% oxygen (56 ppmvd corrected to 3% oxygen) with corresponding annual actual emissions of 43.3 tons per year. MPC assumes for purposes of this example that it is technically feasible to retrofit the existing heater design with ULNB and SCR (i.e., the existing firebox dimensions are acceptable for ULNB under API code and there is sufficient existing physical space for a new SCR system). Consideration of a full heater replacement with ULNB and SCR is also considered in the control technology evaluation to attempt to meet the 2 ppm NOx standard, since the retrofits of the existing heater design cannot reliably achieve this level of performance.

Table 1: Cost-effectiveness calculations for Example 1

Control Technology Option	NOx Performance Level	NOx Emissions Reduction Compared to Current Conditions (tpy)	Annualized Cost ($MM/yr)	25-Year Average Cost-effectiveness ($/ton)	Incremental Cost-effectiveness ($/ton)
Current conditions	41 ppmvd @ 7.9% (56 ppmvd @ 3% O_2), 43.3 tpy NOx actual emissions				
ULNB only	33 ppmvd @ 7.9% O_2 (~20% control)	8.7	0.29	33,375	--
SCR only[1]	92% control (> 2 ppm at outlet)	39.9	1.03	25,777	23,661
Combined ULNB + SCR[1]	Combined 93.6% control (> 2 ppm at outlet)	40.6	1.32	32,483	417,184
Heater replacement with combined ULNB + SCR	*May* meet 2 ppmvd proposed limit	41.4	8.06	200,582	8,060,255

[1] The SCR system is assumed to be 92% efficient in controlling inlet NOx. A SCR system with a greater control efficiency likely would be needed to reach this level of NOx performance, which may not be technically feasible. The costs in this table do not include the substantial costs for these types of SCR systems if it was determined to be technically feasible.

For Example 1, the incremental cost-effectiveness analysis shows that both the combined ULNB and SCR retrofit and the heater replacement control technology options are not cost-effective as compared to the alternative control option of installation of SCR only.

Example 2: Retrofit of SCR Assumed to be Technically Feasible

Example 2 is for a heater with low NOx burner technology for which further reductions with ULNB is technically infeasible and an SCR retrofit is assumed to be technically feasible. Table 2 summarizes the cost-effectiveness for a 100 MMBtu/hr heater at LAR that currently performs at 27 ppmvd NOx at 7.3% oxygen (36 ppmvd corrected to 3% oxygen) with corresponding annual actual emissions of 17.5 tons per year. Consideration of a full heater replacement with ULNB and SCR is also considered in the control technology evaluation to attempt to meet the 2 ppm NOx standard, since the retrofits of the existing heater design cannot reliably achieve this level of performance.

Table 2: Cost-effectiveness calculations for Example 2

Control Technology Option	NOx Performance Level	NOx Emissions Reduction Compared to Current Conditions (tpy)	Annualized Cost ($MM/yr)	25-Year Average Cost-effectiveness ($/ton)	Incremental Cost-effectiveness ($/ton)
Current conditions	27 ppmvd @ 7.9% (36 ppmvd @ 3% O_2), 17.5 tpy NOx actual emissions				
SCR[1]	92% control (> 2 ppm at outlet)	16.1	1.39	86,364	--
Heater replacement with combined ULNB + SCR	*May* meet 2 ppmvd proposed limit	16.4	6.62	404,407	22,148,395

[1] The SCR system is assumed to be 92% efficient in controlling inlet NOx. A SCR system with a greater control efficiency likely would be needed to reach this level of NOx performance, which may not be technically feasible. The costs in this table do not include the substantial costs for these types of SCR systems if it was determined to be technically feasible.

For Example 2, the average and incremental cost-effectiveness values show that both the SCR retrofit and the heater replacement control technology options are significantly above the threshold and thus economically infeasible.

Figure 1 displays the cost-effectiveness results for Examples 1 and 2 relative to the $50,000 per ton cost-effectiveness threshold established by the SCAQMD Governing Board in the 2016 Air Quality Management Plan and to the relative control technology options on an incremental basis.[8]

[8] SCAQMD, "Final 2016 Air Quality Management Plan", Approved March 3, 2017.

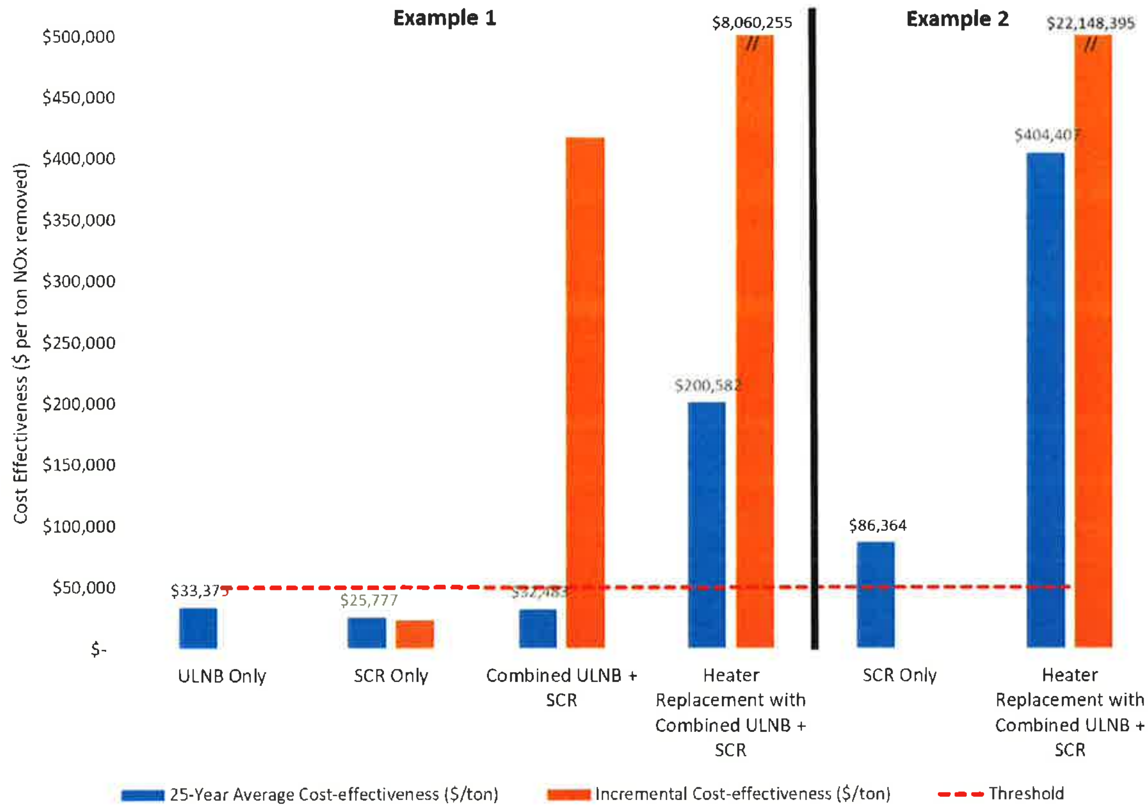


Figure 1: Average and incremental cost-effectiveness analysis for Examples 1 and 2

These two examples are representative of many existing refinery heaters and boilers at LAR when considering the actuality of implementing such retrofit NOx controls and the associated NOx performance and cost. Coupling this with the reality that some heaters cannot be safely retrofitted with ULNB or have no physical space nearby for an SCR, the resulting cost-effectiveness inclusive of redesign, rebuild, or replacement of the heater and/or its associated process equipment, as well as the lost opportunity cost due to additional refinery downtime, far exceeds the $50,000 per ton cost-effectiveness threshold. If SCAQMD is considering major equipment redesign and/or replacement to accommodate ULNB and/or SCR with a new heater design, these costs must be considered in the BARCT analysis.

<u>Norton/FERCo Report Review</u>

The SCAQMD is incorrectly using these third-party reports as the basis for their technical feasibility determinations under BARCT. Attachment C outlines our fundamental concerns with the NEC and FERCo reports that has led SCAQMD to make inappropriate conclusions for BARCT. While the NEC and FERCo studies are informative and speak to many of the safety concerns noted in this letter, there are several technical concerns for ultra-low NOx burners (ULNB) and selective catalytic reduction (SCR) that are either not addressed or that are not addressed appropriately for refinery process heaters.

Conclusions

SCAQMD has not complied with California law and has inappropriately determined BARCT in Proposed Rule 1109.1:

- The SCAQMD has not considered the specific technical feasibility issues associated with installing the same controls on the broad universe of process heater designs at refineries.
- Categorizing refinery equipment based only on heat release duty makes it infeasible to achieve the proposed BARCT NOx levels; Proposed Rule 1109.1's BARCT standards must consider physical characteristics in determining the feasible level of NOx emissions from existing equipment.
- The SCR performance to the level specified in Proposed Rule 1109.1 is technically infeasible for many refinery heaters.
- The SCAQMD's cost-effectiveness determinations ignore actual costs.
- The SCAQMD has not considered the incremental cost-effectiveness calculations for Proposed Rule 1109.1 as required under California Health and Safety Code.

Due to the significant impacts that this rulemaking will have on our refinery and the refining industry as a whole, MPC again requests that Proposed Rule 1109.1 rulemaking be paused to provide adequate time for more meaningful review and comment during this rulemaking process.

Please note that in submitting this letter, MPC reserves the right to supplement its comments as it deems necessary, especially if additional or different information is made available to the public regarding the Proposed Rule 1109.1 rulemaking process.

Thank you for the opportunity to provide comments. We are glad to discuss further and look forward to continued dialogue.

Sincerely,

Bradley J Levi

Brad Levi
Vice President – Los Angeles Refinery

Attachments

cc: ***SCAQMD***
Sarah Rees – Acting Deputy Executive Officer
Susan Nakamura – Assistant Deputy Executive Officer
Michael Krause – Planning and Rules Manager

cc: ***SCAQMD Governing Board Refinery Committee***
Dr. William Burke – Governing Board Chairman
Hon. Ben Benoit – Governing Board Vice-Chairman and Refinery Committee Member
Hon. Larry McCallon – Governing Board Member and Refinery Committee Chairman
Hon. Lisa Bartlett – Governing Board Member and Refinery Committee Member

cc: ***SCAQMD Governing Board***
Hon. Joe Buscaino – Governing Board Member
Hon. Michael Cacciotti – Governing Board Member
Hon. Vanessa Delgado – Governing Board Member
Hon. Gideon Kracov – Governing Board Member
Hon. Sheila Kuehl – Governing Board Member
Hon. V. Manuel Perez – Governing Board Member
Hon. Rex Richardson – Governing Board Member
Hon. Carlos Rodriguez – Governing Board Member
Hon. Janice Rutherford – Governing Board Member

ecc: 2021-02-01 MPC Second Comment Letter on Revised Draft of SCAQMD PR1109.1
Greg Busch, MPC RE
Ruth Cade, MPC RE
Chris Drechsel, MPC RE
Ben Franz, MPC LAW
Denis Kurt, MPC LAR
Robert Nguyen, MPC LAR
Tim Peterkoski, MPC EA
Robin Schott, MPC LAR
Vanessa Vail, MPC LAW

ATTACHMENT A

Larry David "David" Wilson

Sr. Technical Lead – Oil & Gas

Resume Highlights
Fired Equipment Specialist
Management
Field Installation Review
Troubleshooting
Inspection
Design Emergency Shutdown Systems
Wrote Emergency Procedures

Job Title:
Senior Technical Lead, Oil & Gas

Years with EN Engineering: 5

Total Years of Experience: 40+

Primary Office Location:
Catlettsburg, KY

Education:

- Master of Science in Mechanical Engineering from the University of Kentucky, 1976
- Bachelor of Science in Aerospace Engineering from West Virginia University, 1972

Military United States Air Force Education Experience:

- Air University Diploma in communications, leadership, management, tactics, and strategy, 1999
- Federal Emergency Management Agency (FEMA), Emergency Management Institute Course for managing multiple projects.
- Air Command and Staff School Diploma in communications leadership, management, tactics, and strategy, 1990

Overview: An engineering manager, fired equipment specialist, and mechanical engineer with over 40 years of experience working for two large petroleum companies and two consulting engineering firms.

Relevant Projects & Experience:

EN Engineering, Catlettsurg, KY, Senior Technical Lead. Trained operators and engineers on the design, operation, safety systems, troubleshooting, heater tuning, and maintenance for fired heaters, ultra-low NOx burners (ULNBs), combustion air preheaters (APHs), selective catalytic reduction (SCR) units, forced draft (FD) fans, and induced draft (ID) fans at a major refinery. Trained operators and engineers on the design, operation, safety systems, troubleshooting, heater tuning, and maintenance for fired heaters, ultra-low NOx burners (ULNBs), combustion air preheaters (APHs), selective catalytic reduction (SCR) units, forced draft (FD) fans, and induced draft (ID) fans at a major petrochemical plant. Reviewed and recommended changes to the design, operation, and control of a platformer heater and its air preheater (APH), selective catalytic reduction (SCR) unit, forced draft (FD) fan, and induced draft (ID) fan. Reviewed and recommended changes to a major refiner's fired heater specifications. Developed operator heater training program and trained operators and engineers for Texas Transmission Company. Analyzed the heat transfer and stresses on a waste heat generator exchange tubes and recommended changes to improve tube life. Developed designed conditions, wrote heater specification, developed heater data sheets, submitted proposal to heater vendors, analyzed bids, and recommended a vendor for a large transmission company. Performed steam and boiler studies and recommended a new boiler purchase for petrochemical plants. Sized and specified relief valves for supercritical fluid vessels.

EEC, Catlettsburg, Mechanical Lead. Developed operator heater training program and trained operators for a major Texas petrochemical plant. Analyzed and specified relief valves for boilers and natural gas transmission compressors. Designed, wrote specifications, developed control and burner management systems, oversaw installation, trained operations and maintenance personnel, start – up and tested a new boiler and boiler feedwater pumps for a chemical plant. Troubleshot, analyzed, and recommended solutions for a boiler feedwater corrosion problem at a marine terminal. Evaluated several heat exchangers designs by using TEMA and ASME Section VIII, Div 1 for an ethylene plant. Wrote specifications based upon API - 610 and analyzed two new boiler feedwater pumps at a major chemical plant. Wrote specifications based upon ASME Section I and analyzed a new boiler and its ancillary equipment for a major chemical plant. Analyzed heat treating furnace at a major steel mill. Analyzed and reported on several heat recovery steam generators (HRSG) performance at a major coke plant. Performed a study on installing large duct burners to increase HRSG steam production for power generation in peak power periods at a major coke plant. Presented classes on boiler fundamental to customers.

Marathon Petroleum Company, Findlay, Fired Equipment Specialist. Developed and implemented a program in 2000 to retrofit several existing process heaters with low NO_x burners (LNBs) on several heaters at several refineries in order to comply with a Federal Consent Decree; oversaw the installation of the LNBs. Wrote and reviewed standards and emergency procedures, designed emergency shutdown systems, reviewed operating and maintenance procedures; wrote heater, boiler, rotating equipment training

Military United States Air Force Education Experience (cont’d):

- Squadron Officers School Diploma in communications, leadership, management, tactics, and strategy, 1984
- Graduate from Air Force Pilot Training, 1976

Air National Guard Work Experience

- Veteran of Desert Storm 1991.
- C–130H Command Pilot.
- Chief of Operations Command and Control.
- Chief of Maintenance Aircraft Quality Control and Functional Check Flights.
- Deployed Acting Maintenance Commander.

Professional Registration:

- Licensed Professional Engineer, KY 1980-Current

Professional Organizations & Affiliations:

- Served on the Subcommittee for Mechanical Equipment as a member of the committee.
- Responsible for the team development of API standards in the petrochemical industry.
- Served on the Committee for Refinery Equipment (CRE) and served a term as committee chair.
- Served on the Subcommittee on Heater Transfer as a sponsor from CRE.

programs for engineers, operators, and maintenance personnel; trained engineers, operators, and maintenance personnel. Specified, designed, purchased, troubleshot, analyzed, and re-rated fired equipment such as fired process heaters, boilers, burners, incinerators, and flares for seven refineries. Solved unique heat transfer, fluid dynamics, and thermodynamic problems and implemented solutions associated with refinery equipment such as FCC’s, Sulfur Units, Crude Units, Vacuum Units, Coker Units, Hydrogenation Units, heaters, boilers, etc. Solved refractory material and installation problems and implemented solutions for vessels, ducts, and heaters. Applied these skills along with field installation review, inspection, and start-up assistance to 12 fired process heaters and a fired package boiler to complete one major project totaling over 1.5 billion dollars.

Ashland Petroleum Company, Ashland, Manager of Mechanical Technologies and Reliability. Managed engineers who were responsible for the process safety management, i.e., OSHA’s 1910.119 regulation and for reliability, design, purchase, troubleshooting, analyzing, writing standards, and re-rating of fired, unfired, fixed, rotating, and utility equipment for three refineries. Wrote reliability and mechanical integrity programs.

Ashland Petroleum Company, Maintenance Manager of Refinery Projects, Engineering, and Planning. Managed engineers and technicians who were responsible for maintenance planning, projects, and the reliability of the fired, unfired, fixed, rotating, and electrical equipment for the Catlettsburg Refinery.

Ashland Petroleum Company, Mechanical and Power Engineer. Provided design, specifying, purchasing, troubleshooting, analyzing, and re-rating assistance for rotating equipment such as pumps, compressors, and steam turbines and for both fired, unfired, and fixed equipment such as fired process heaters, boilers, burners, deaerators, cooling towers, heat exchangers, piping systems, and emergency shutdown systems.

ATTACHMENT B

ENengineering

Comprehensive and Dependable Engineering, Consulting, and Automation Services

Feasibility Considerations for NO_X Emissions Control Retrofits at Existing Refinery Process Heaters

Prepared for
Marathon Petroleum Corporation

January 2021

Feasibility Considerations for NO_X Emissions Control Retrofits at Existing Refinery Process Heaters

January 2021

Contents

List of Figures

Executive Summary

Refineries operate many different designs of heaters with unique process fluids, tube materials, shapes and sizes, burner orientations, firing conditions, tube orientations, and draft types. There is no "one size fits all" feasible ULNB/SCR retrofit for existing refinery heaters. Not all existing process heaters can be safely retrofitted with ULNBs and SCRs due to flame impingement and related safety risks, inadequate area in and around the heater for operating and maintaining the heater safely, and lack of physical space to install, operate, and maintain post-combustion emissions control equipment.

It is imperative that any existing refinery process heater being considered for a ULNB retrofit is first assessed for its capability to be safely operated and maintained with the new technology. Design standards and recommended practice documents from the American Petroleum Institute (API), as well as company-specific refinery heater and burner specification documents, provide the technical criteria for a case-by-case NOx emissions control retrofit evaluation. Computational fluid dynamic (CFD) modeling is conducted on the specific heater's physical design and variable operating conditions to support the technical feasibility analysis.

Similarly, determining the feasibility and performance of installing SCR technology on an existing refinery process heater requires a case-by-case assessment of the exhaust conditions (i.e., NOx and excess oxygen concentrations and operating temperature range) and the available physical footprint to accommodate the SCR infrastructure.

Therefore, four possible scenarios result from conducting a feasibility analysis of retrofitting existing process heaters with ULNBs and SCRs:

1. ULNBs may not be safely installed due to flame impingement and/or operations and maintenance personnel's inability to safely execute their duties, and an SCR cannot be installed due to limited available space or excessive installation costs.
2. ULNBs may be safely retrofitted in an existing process heater, but an SCR may not be installed due to limited space or to structural concerns with the heater foundation (if constructed vertically) or at other nearby platform support structures if space if available. Depending on the type of ULNB, required turndown, the fuel gas composition, tramp air, safe operating conditions, and combustion air preheat, the controlled NOx from the installation is normally in the range of 25 to 50 parts per million on a volume dry basis (ppmvd) corrected to 3% excess oxygen.
3. ULNBs may not be safely installed due to flame impingement and/or operations and maintenance personnel's inability to safely execute their duties, but an SCR may be safely installed. Depending on the type of burner in the existing process heater, combustion air preheat, safe operating conditions, excess air (oxygen), tramp air, and the heater's operating mode, the NOx formation entering the SCR could be between 50 to 130 ppmvd. The SCR NOx removal efficiency and any associated outlet NOx limit must consider real-world operational variability and deviations from the theoretical assumptions used in the initial SCR design. With a reliably proven and sustained NOx removal efficiency of 92% for most installations with a higher inlet NOx concentration, the

corresponding outlet NOx from the SCR is normally 4.0 to 10.4 ppmvd with a corresponding maximum ammonia slip limit of 10 ppmvd to sustainably meet the underlying NOx limit during normal operations.

4. ULNBs may be safely installed and an SCR may also be safely retrofitted at the existing process heater. From scenario #2 above, the ULNB-controlled NOx concentration is normally 25 to 50 ppmvd corrected to 3% excess oxygen. The SCR NOx removal efficiency and any associated outlet NOx limit must consider real-world variability and deviations from the theoretical assumptions used in the initial SCR design. Given the lower NOx concentration entering the SCR, the sustained NOx removal efficiency may be lower than that in scenario #3. At a 92% control efficiency, the outlet NOx is 2.4 to 4.0 ppmvd with a corresponding maximum ammonia slip limit of 10 ppmvd to sustainably meet the underlying NOx limit during normal operations.

Any emissions limits for NOx, ammonia, and other pollutants that are established for retrofit NOx controls at a refinery heater under scenarios #2 to #4 above must consider the inherent variability in operating conditions that appreciably impact the actual control efficiency on a short-term basis.

SCAQMD's Proposed Rule 1109.1 requires every existing refinery process heater with a design heat release of 40 MMBtu/hr or greater on a higher heating value (HHV) basis to meet 2 ppmvd NOx and 5 ppmvd ammonia slip corrected to 3% excess oxygen (O_2) and on a 24-hour rolling average. These limits and associated averaging period are not proven and/or are infeasible for many existing refinery heaters. For those heaters that can potentially meet these emission limits under ideal conditions, the limits as proposed provide no margin for compliance with respect to the inherent operational variability that is experienced by refinery process heaters.

This paper outlines in Section 1 the different types of process heaters used at refineries and their associated combustion design factors. Key characteristics that are considered by engineers to determine the feasibility of retrofitting these distinct designs of refinery process heaters with NOx emissions controls are described in Section 2. Section 3 presents four possible NOx control retrofit cases or scenarios that will result from a given feasibility analysis of applying ULNBs and SCR at an existing heater and the corresponding level of NOx performance expected during normal operations following the retrofit project.

1 Common Refinery Heater Types and Design Factors for NOx Controls

Process heaters are classified in different ways. The South Coast Air Quality Management District (SCAQMD) classifies heaters per their heat release on a higher heating value (HHV) basis. However, for a given heat release or heat release range, heaters come in different physical shapes, sizes, burner orientations, process fluid types, tube materials, firing conditions, coil orientations, and air drafts. When evaluating existing heaters to be retrofitted with ultra-low NOx burners (ULNBs) and selective catalytic reduction (SCR) units, these other heater design criteria for a given heat release or heat release range will significant influence whether the existing process heater or boiler can accommodate the proposed NOx control technology.

This section explains the different heater classifications at a given heat release or heat release range that are common to the petroleum refining sector.

1.1 API and Company-specific Standards for Safe Heater Design, Operation, and Maintenance

It is important to first recognize that design standards and recommended practice documents from the American Petroleum Institute (API) as well as company-specific refinery heater and burner specification documents provide the technical criteria for the design of heaters and combustion systems for safe operation. Throughout this report, reference is made to four API documents: API-535 (reference 1), API-536 (reference 2), and API-560 (the currently published Fifth Edition and approved Addendum 1 to be published, references 3 and 4). These documents govern the design, operation, and maintenance of burners for fired heaters, post-combustion NOx controls (i.e., SCR), and fired process heaters in general refinery service, respectively. These documents have been revised over the years to address emerging technologies (i.e., ULNB), as well as learnings from safety and operational incidences that have occurred for the various types of refinery heaters that are used today.

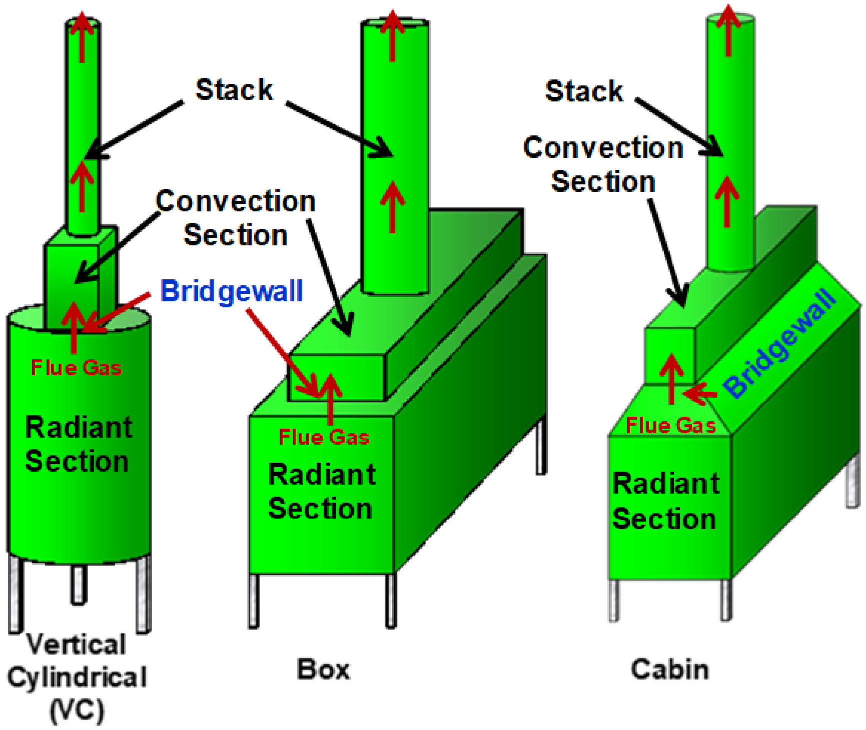
These API and related company-specific documents (e.g., reference 8) address recognized and generally accepted good engineering practices (RAGAGEP) for refinery process heaters, burners, and post-combustion NOx controls. By adhering to the specified procedures and criteria when evaluating future modifications, such as adding combustion controls or installing post-combustion technology, to a heater complex, the technical feasibility of such changes can then be determined. For example, in order to satisfy API standards, ULNB retrofits for natural draft heaters may require a complete redesign of the heater floor, new fuel gas piping, additional instrumentation and controls, a new induced draft fan, and electrical upgrades for flame scanners and pilot ignition. For some existing heater designs, installing ULNBs cannot meet the API standards without a complete reconstruction or replacement of the heater, which effectively means that the heater design cannot be feasibly retrofitted.

When evaluating the feasibility of changes at a heater that may impact combustion, computational fluid dynamic (CFD) modeling is conducted for the given specific heater design and the new technology option being considered. CFD modeling is an advanced engineering calculation procedure that uses complex engineering algorithms to simulate the combustion and flue gas flow characteristics inside the burner and heater to determine if flame impingement may occur. This simulation analysis provides an understanding of the heater's impacts on safety (i.e., heat flux, tube metal temperature) for comparison to the API and company-specific design standards associated with a potential retrofit of new burners or associated combustion equipment.

These design standards contain technical criteria that apply to different types of furnace designs and burner characteristics. Understanding these key heater and burner design characteristics is essential to evaluating the feasibility of retrofitting a given heater with new NOx emissions controls.

1.2 Shape and Size Characteristics

Process heaters are classified by their dimensional shape and physical size. Three common process heaters shapes are illustrated in Figure 1-1.



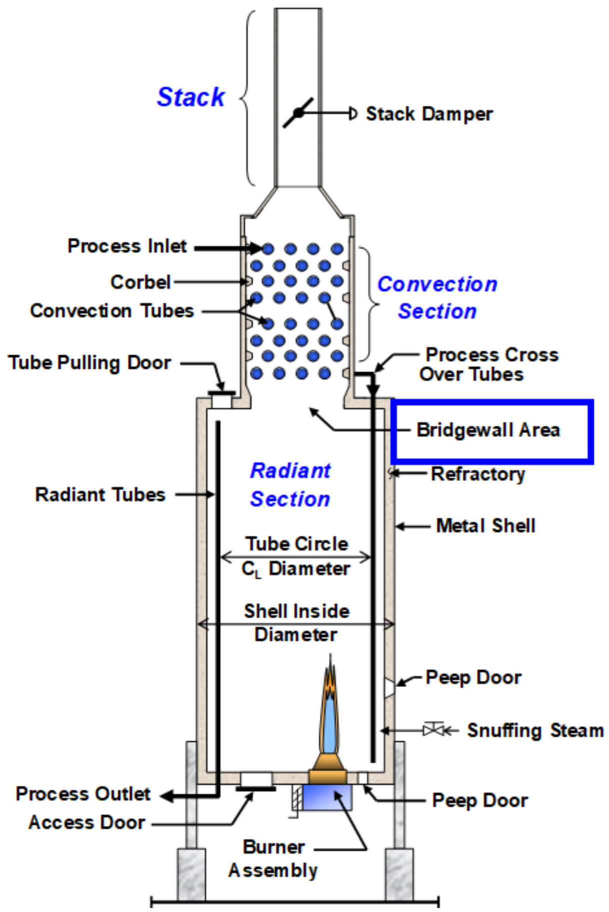
Source: reference 9

Figure 1-1 Common physical shapes of petroleum refinery process heaters.

The three common types of heaters are referred to as vertical cylindrical (VC), also called a "can" heater, box, and cabin heaters. The shape and physical size set the existing physical geometry that all internal equipment must fit inside, such as interior tubes that hold process fluid, burners, and interior target-fired walls. Each unique configuration needs to be evaluated for the feasibility of installing NOx emissions controls.

Figure 1-1 also shows the flue gas flow and the basic areas of the heater: radiant section, bridgewall, convection section, and stack. Generally, the process fluid absorbs about 60% to 70% of the total required absorbed duty while the convection section absorbs approximately 30% to 40%. Very few heaters may not have a convection section, in which case the flue gas temperature leaving the heater may be over 1,250°F. The flue gas is made in the radiant section, flows from the radiant section through the convection section, and out the stack. The bridgewall is the area where the flue gas leaves the radiant section and enters the convection section and is a key location where temperature, pressure, and excess oxygen are measured to safely control the heater.

These areas of the heater and other more detailed components of refinery heaters relate to safe design parameters that are found in API and company-specific documents. Figure 1-2 is an illustration of a VC heater identifying these areas and components for reference.



Source: reference 9

Figure 1-2 Areas and components of a refinery process heater.

API and company-specific heater design documents refer to the bridgewall or to other areas and components of the heater for safe design parameters. Some examples of these parameters that are described in this report include minimum clearance from grade to burner, maximum floor firing heat flux density, maximum tube metal temperature, etc.

1.3 Burner Orientations and Firing Conditions

Four types of burner orientations are normally found at refinery heaters, including fired upward, fired downward, fired horizontally to a target wall, or fired horizontal to an opposed burner. Each orientation poses unique conditions that may lead to unacceptable flame coalescence or impingement for ULNB retrofits. Such flame impingement on various heater surfaces can be catastrophic. For example:

- Flame impingement on process tubes will overheat the tubes, which may result in a tube rupture and a firebox explosion.
- Flame impingement on the tube hangers will cause the hangers to overheat, break, and allow the tube to fall near or into the flame.
- Flame impingement on the refractory surfaces may overheat the refractory, cause the refractory to fall (spall) off the metal shell, and overheat the metal shell creating cracks in the shell. Because operations and maintenance personnel must work near the heater, cracks in the metal shell becomes a safety issue and should be avoided. If the metal shell crack is large enough, the structural integrity of the heater may be significantly compromised, and the heater may collapse.

Figure 1-3 shows both an unfavorable (left) and a favorable (right) flame to flame interaction and coalescing patterns, for example.

Unfavorable flame patterns **Favorable flame patterns**

images courtesy of MPC

Figure 1-3 Unfavorable and favorable flame to flame interaction and coalescence.

Guidelines for burner spacing are found in industry standards such as API-535 (reference 1), API-560 Addendum 1 (reference 4), or in company-specific standards (e.g., reference 8) that are based in part on these API publications.

1.3.1 Burner Configuration in Vertical Cylindrical Heaters

Vertical cylindrical (VC) heater burners are arranged in a circle on the floor and fired upward. The diameter of the burner circle can restrict the ability to perform burner retrofits. If the burner circle diameter is too small (i.e., burner to burner spacing will be too close), the flames will coalesce and grow with a potential of flame impingement on the shock tubes or arch refractory. If the burner circle diameter is too large (i.e., burner to burner spacing will be too far apart), the radiant section flue gas circulation currents will “pull” the flames into the tubes.

Significant engineering analysis, including CFD modeling, is necessary to evaluate whether flame impingement or flame coalescing has the potential to occur. To fully understand whether ULNBs can be safely installed for the equipment, each existing process heater must be individually evaluated.

Flame length restrictions are highly dependent on the heater height. Figure 1-4 shows two side-by-side natural draft VC heaters of different sizes.

image courtesy of MPC

Figure 1-4 Two vertical cylindrical heater configurations.

The firebox for the jet reboiler is only 13 feet tall, which constrains long flame envelopes associated with ULNB technology and thus may be infeasible to retrofit. Burner retrofits must comply with API-560 Addendum 1, API-535, and company-specific vertical spacing requirements. Likewise, the Jet R-3 Heater is 21 feet tall; taller than the Jet Reboiler Heater, but still may present a problem in installing ULNBs.

1.3.2 Burner Configuration in Upward Fired Cabin or Box Heaters

Figure 1-5 shows a small natural draft cabin heater that is upward fired.

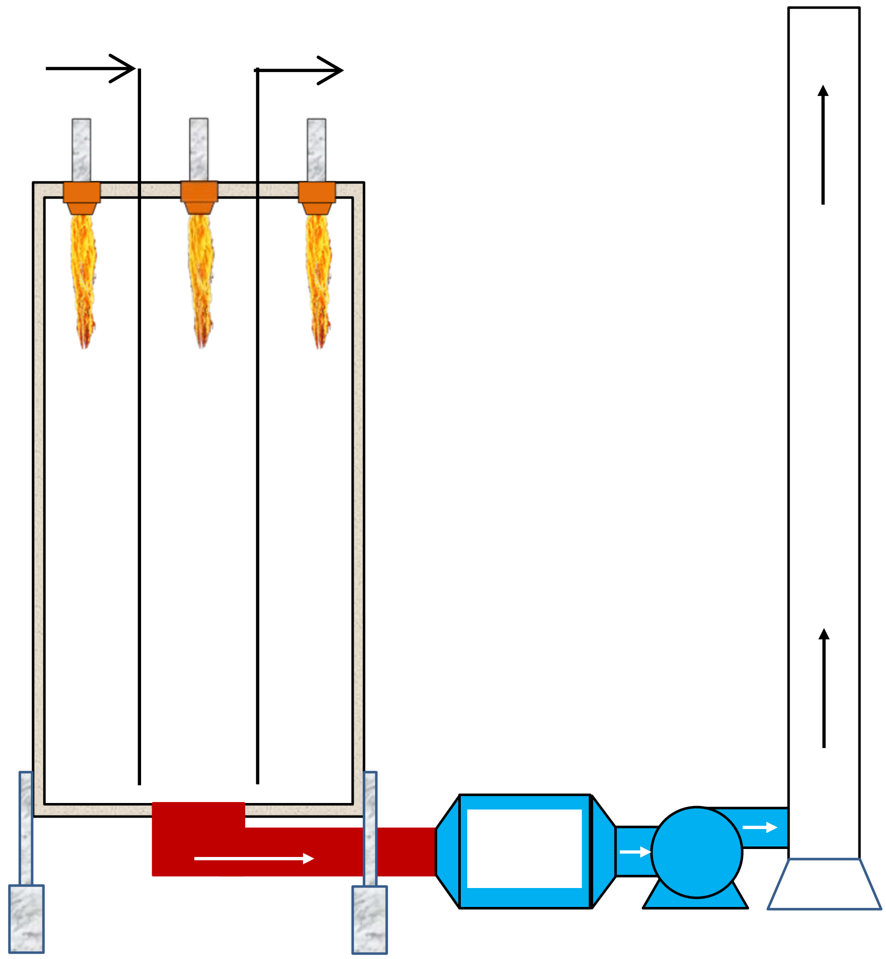
image courtesy of MPC

Figure 1-5 Upward fired natural draft cabin heater.

Upward fired cabin or box heater burners usually are arranged in-line down the length of the heater. If the burner to burner spacing is too close, the flames will coalesce and grow with a potential of flame impingement on the shock tubes or arch refractory. If the burner to burner spacing is too far apart, the radiant section flue gas circulation currents will "pull" the flames into the tubes. Safely installing ULNBs may not be possible in order to avoid flame impingement. Conformance with API-560 Addendum 1, API-535, and company-specific design standards must be evaluated on an individual basis.

As with vertical cylindrical heaters, a CFD model may be necessary to determine the feasibility of retrofitting a heater such as this with ULNBs.

Downward fired burners in refinery process heaters are less common than upward firing burners. An example illustration of downward firing burners is in Figure 1-6.



Source: reference 9

Figure 1-6 Downward fired cabin heater illustration

If the burner to burner spacing is too close to each other, the flames will coalesce and grow with a potential of flame impingement on the floor refractory. The radiant section flue gas circulation currents may "pull" the coalescing flames into the tubes.

1.3.3 Burner Configuration in Horizontal Fired Cabin or Box Heaters

Wall mounted horizontally fired burners pose unique flame length restrictions given the proximity to target walls or other burners mounted opposite of them. Figure 1-7 shows a horizontal fired box heater.

image courtesy of MPC

Figure 1-7 Horizontal fired "3-in-1" box heater.

The horizontally fired box heater above includes pressure relief doors, which are normally sources of infiltration air, also called tramp air.

Figure 1-8 shows an example schematic of a cabin heater CFD model with two horizontally opposed burners.

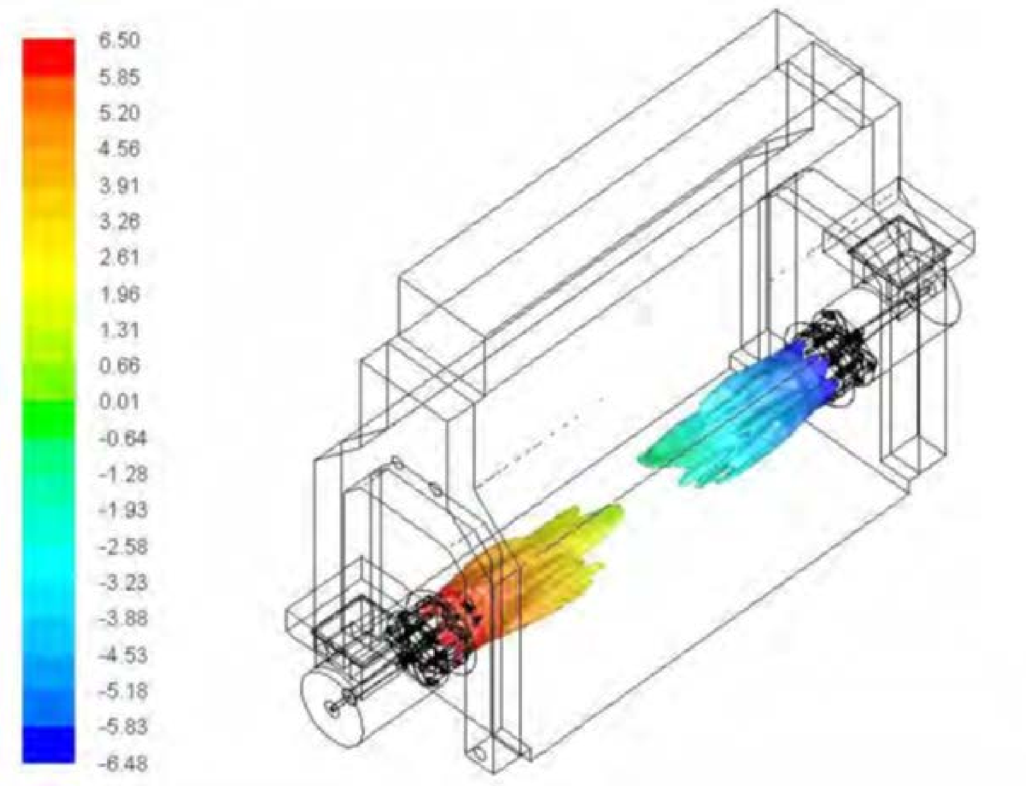
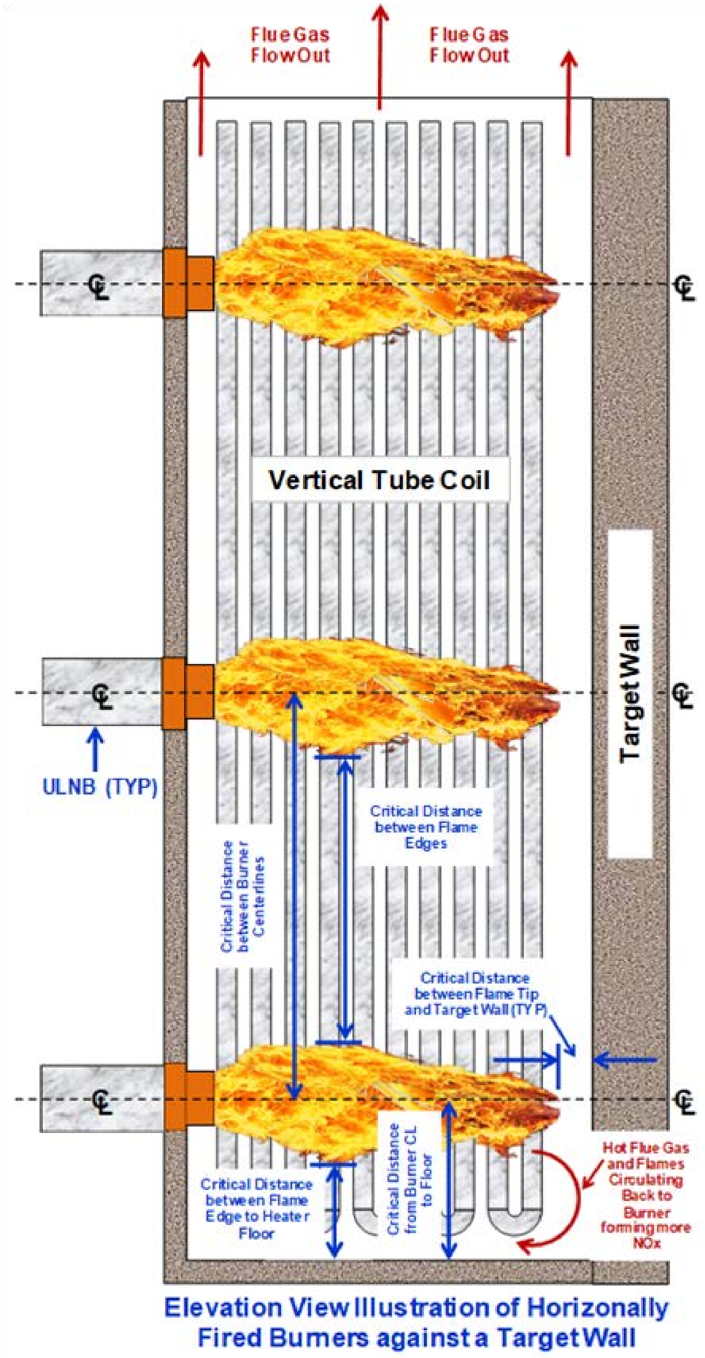


image courtesy of MPC

Figure 1-8 CFD model of horizontal fired cabin heater.

This example shows some space between the flame tips; however, some existing process heater designs may not have this space when ULNBs are installed. If adequate burner-to-burning spacing does not exist, then the flames will interact with either other, spread outward, and impinge on the tubes. Even with enough flame tip spacing between the burners, the radiant section internal currents may pull the flames into the radiant section tubes.

Figure 1-9 shows a burner firing towards a target wall for an operating heater.



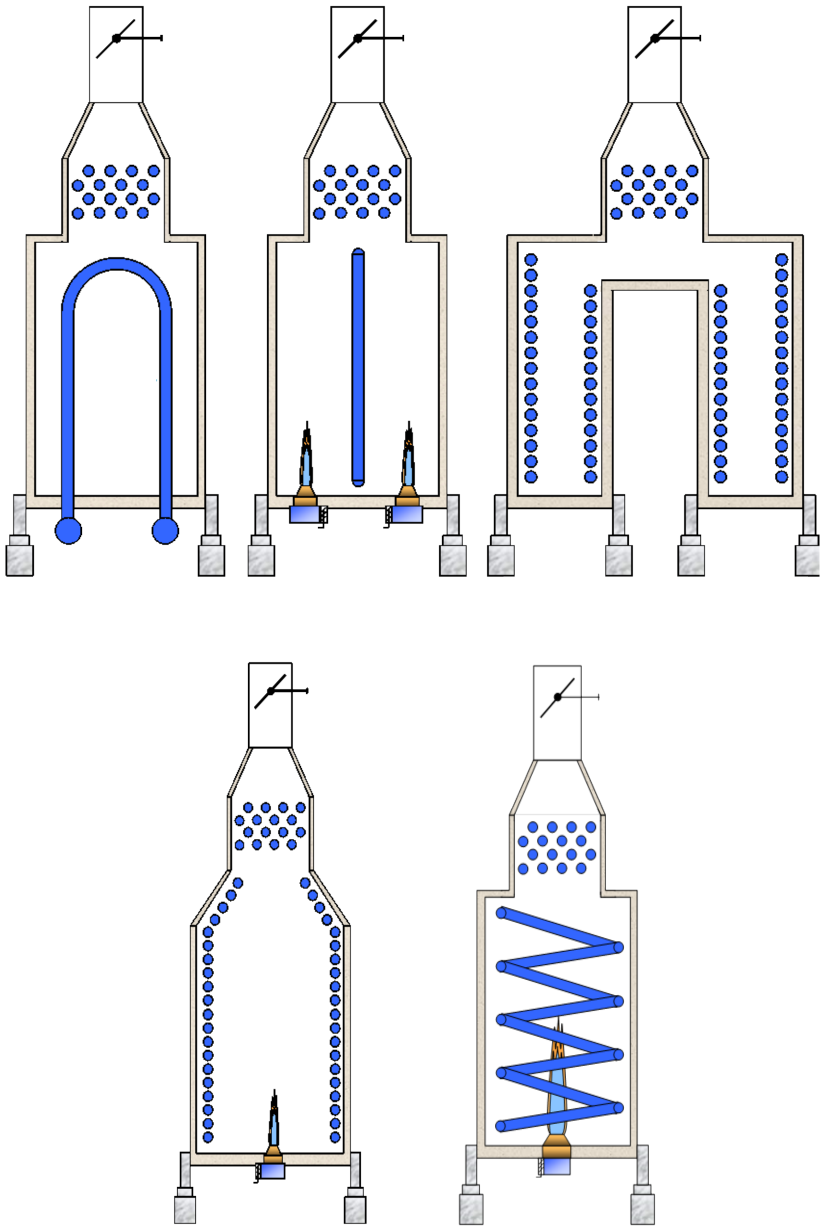
Source: reference 6

Figure 1-9 Burner firing towards a target wall.

Installing ULNBs with long flames may hit the target wall, spread out, impinge on the tubes, and create additional NOx by hot flue gas and flames near the floor circulating back to the burner. Also, if the flame envelopes are too close to each other, they may spread out and impinge on the process tubes. These consideration must thoroughly be evaluated against the API and company-specific design standards before installing ULNBs at an existing heater.

1.4 Process Coil (Tube) Arrangements Relative to Burners

Process heater tubes can be arranged in several different manners. Each design has unique burner constraints to avoid burner coalescence or flame impingement. Figure 1-10 shows several heater tube and burner arrangements found in the refining industry.

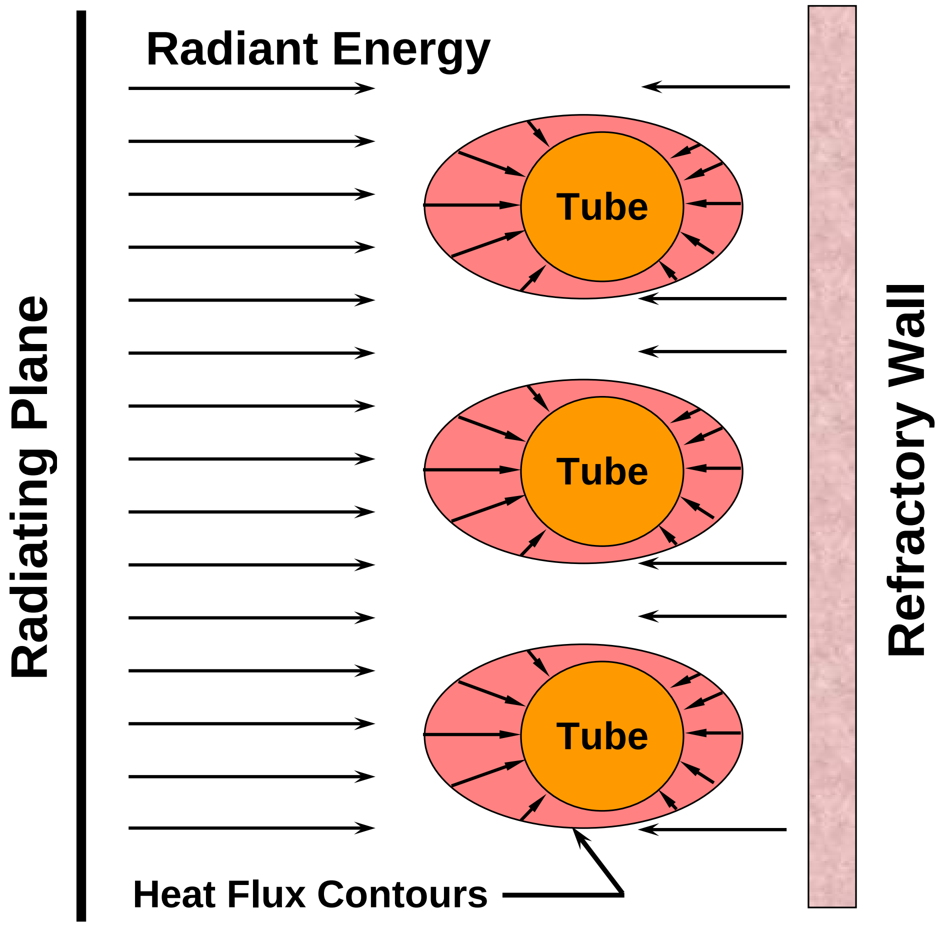


Source: reference 9

Figure 1-10 Process coil and burner orientations.

In evaluating existing process heaters for retrofitting with NOx emissions controls, the coil configurations, burner conditions, and corresponding spacing between the coils and burners need to be considered to ensure that flame impingement does not occur.

Transfer of heat from the burners to the process coils depends on the tube, burner, and refractory wall arrangements. Figure 1-11 shows an illustration of a single fired heater.

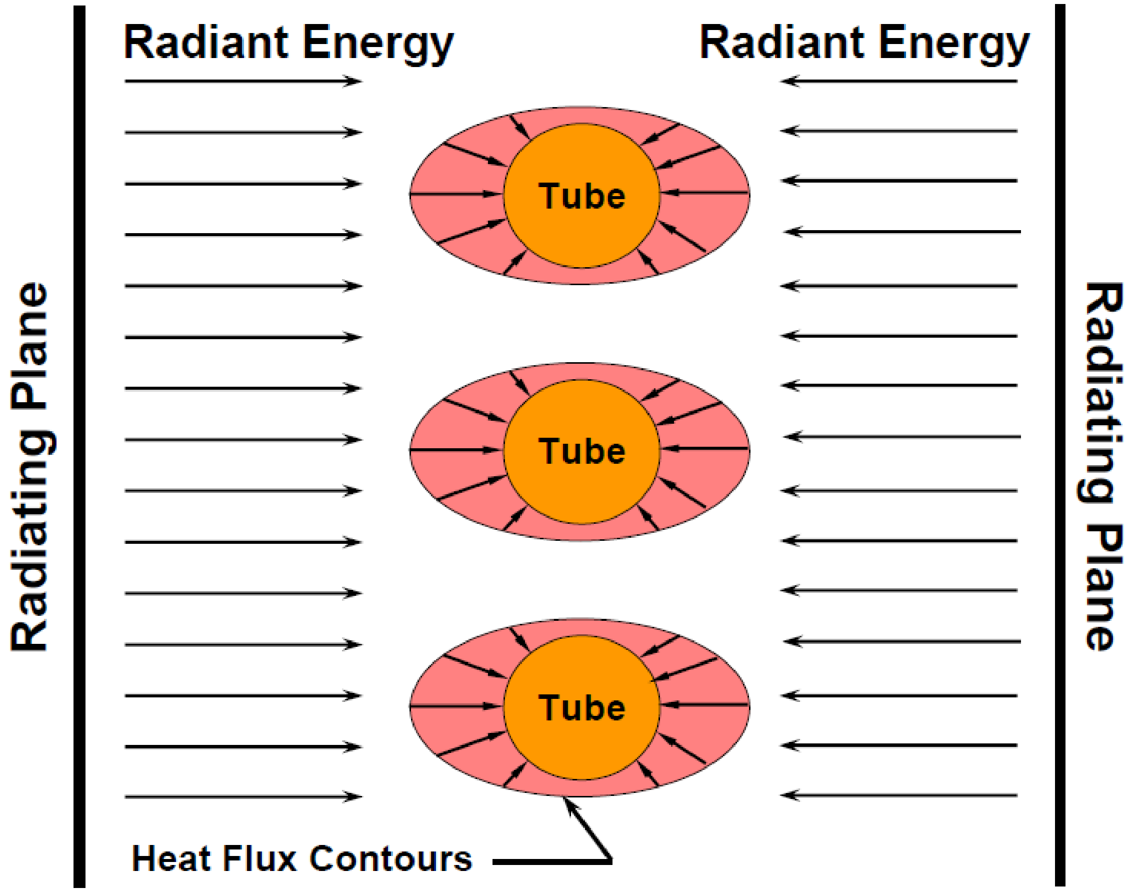


Source: reference 9

Figure 1-11 Heat transfer for a single fired process heater.

In this example, the flame from the radiating plane is on one side of the tube, so the maximum heat flux is on the front side of the tube facing the radiating plane. The maximum heat flux can be 1.8 to 1.9 times the average heat flux, which may present a concern for tube integrity. This firing condition needs to be considered when evaluating the feasibility of retrofitting burners in existing process heaters, as it could increase the heat flux at the tubes and refractory wall.

Figure 1-12 shows a heat transfer illustration of a double fired heater.



Source: reference 9

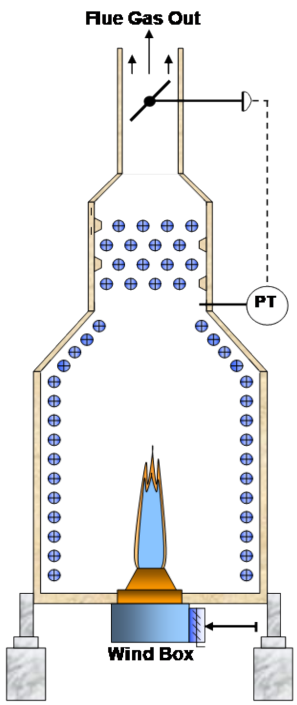
Figure 1-12 Heat transfer for a double fired process heater.

For this design, flames are located on both sides of the tube. In theory, the heat flux should be the same on both sides of the tubes. Even so, spacing between the burner flames and tubes must be sufficient to ensure no flame impingement occurs at the tubes for any ULNB retrofit project.

1.5 Heater Draft Conditions

Four basic draft conditions exist for process heaters: natural draft, induced draft, forced draft, and balance draft. Each style presents its own inherent challenges and limitations to install ULNBs and SCRs at existing process heaters.

Figure 1-13 illustrates a single fired natural draft cabin heater with horizontal coils.



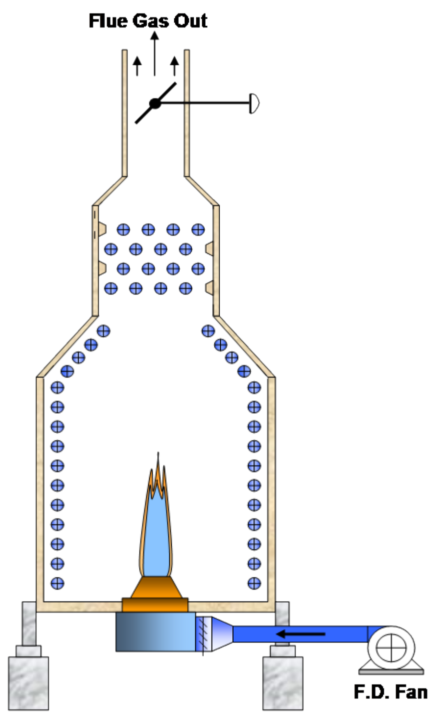
Source: reference 9

Figure 1-13 Natural draft cabin heater.

Natural draft heaters are very common in refineries. VC, box, and cabin heaters can all be natural draft. In order to satisfy API standards, ULNB retrofits generally require heater floor redesigns, new fuel gas piping, controls, instrumentation, a new induced draft (ID) fan (changing heater from natural draft to induced draft due to increased flue gas pressure drop), and possible electrical upgrades for the ID fan, flame scanners and pilot ignition.

Installing an SCR on top of the convection section may not be possible because this would create excess stresses on the existing heater structure and foundation. The space around the heater needs to be evaluated to determine if sufficient usable space is available for installation of an SCR and its ancillary equipment (i.e., ammonia skid, ammonia storage tank, induced draft fan).

Figure 1-14 shows a single fired, forced draft cabin heater with horizontal coils.

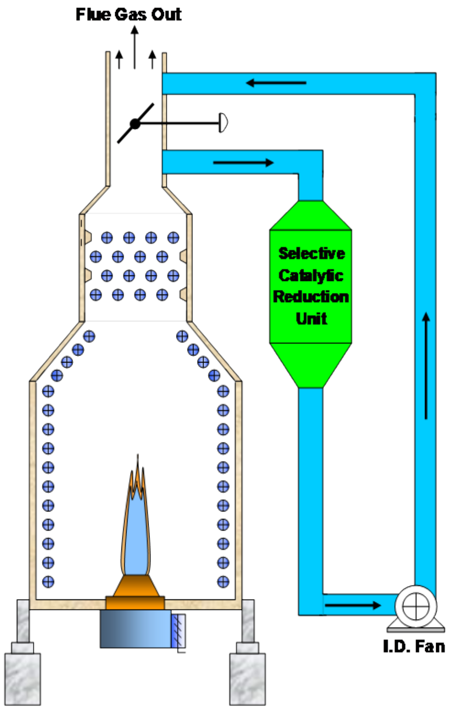


Source: reference 9

Figure 1-14 Forced draft cabin heater.

Forced draft heaters are not very common in refineries. VC, box, and cabin heaters may be forced draft. ULNB retrofit considerations for forced draft heaters are similar to natural draft heaters. Forced draft heaters may change to an induced draft or balance draft heater in order to accommodate ULNBs.

Figure 1-15 shows a single fired, induced draft cabin heater with horizontal coils.

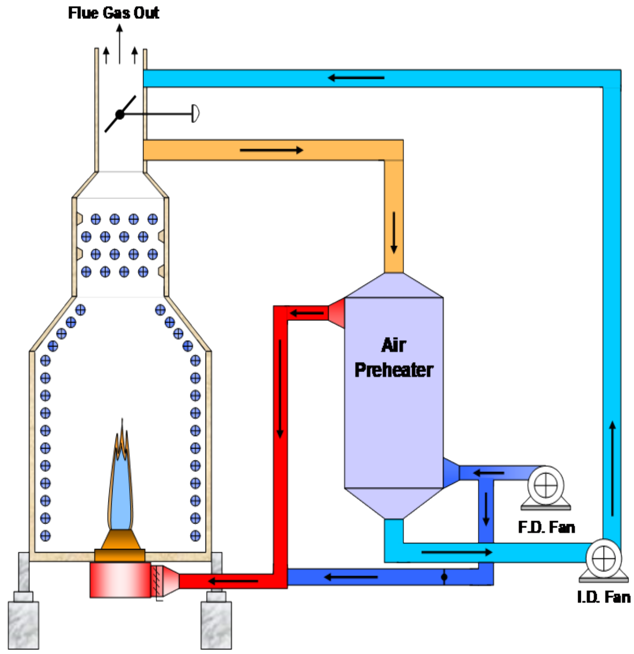


Source: reference 9

Figure 1-15 Induced draft cabin heater.

VC, box, and cabin heaters may be induced draft. This illustration shows a retrofitted SCR to either a natural draft or induced draft heater. Because of the increased pressure drop, an induced draft (ID) fan is necessary to overcome the pressure drop. Cooling the flue gas going to the ID fan, not shown in the illustration, may be necessary for the fan design and operation.

Figure 1-16 shows a single fired, balanced draft cabin heater with horizontal coils.



Source: reference 9

Figure 1-16 Balanced draft cabin heater.

VC, box, and cabin heaters may be balanced draft. The primary purpose of a balanced draft heater is to reduce fuel flow and recovery energy for a given process absorbed duty. By installing an air preheater (APH), the combustion air temperature increases and the flue gas temperature decreases. The result is a reduction in fuel flow for the same process absorbed duty. Retrofit considerations for ULNB in a balanced draft heater are the same for a natural draft heater except the combustion air duct to the burners will also need to be modified.

Retrofitting an SCR to a balanced draft heater may be difficult and costly. The SCR could potentially be placed on top of the APH provided that the existing structure and foundation can accommodate the added stress and if sufficient usable space is available.

The SCR could potentially also be located aside the APH depending on the available space. Necessary roadways for operations, maintenance personnel, first emergency responders, equipment should not be considered available space. Equipment laydown and staging areas should also not qualify as available space.

Replacing the APH with the SCR is not recommended, since a greater fuel firing rate will be needed to maintain the same process absorbed duty demand. As a result, the heater may need to be re-permitted to account for the increased firing rate, energy usage and operating costs will increase, and additional carbon dioxide, a greenhouse gas, will be generated.

2 Design and Operational Characteristics for NOx Control Retrofits

There are several technical considerations for retrofits of existing heaters with ULNBs and SCRs. Specifics for each are included below.

2.1 Mechanisms of NOx Formation

NOx formation is well known for the past 40 years. NOx is formed by atomic nitrogen and oxygen combining to form nitric oxide (NO) and nitrogen dioxide (NO_2) plus other less prevalent NOx species. In process heaters, NO is predominant at about 95% of the total NOx while the remainder is NO_2 at heater design conditions. A higher flue gas oxygen content during turndown operations will result in a relative increase in NO_2 formation. For calculation purposes, SCAQMD considers all NOx to be NO_2.

NOx formation is classified as thermal, fuel bound, and prompt NOx. Thermal NOx is formed from high temperature dissociation of nitrogen and oxygen molecules into atomic nitrogen and oxygen. The atomic nitrogen and oxygen combine to produce NOx compounds, primarily NO. Fuel bound NOx is produced by burning fuels with nitrogen compounds. The atomic nitrogen is release during the combustion process and combines with atomic oxygen to produce NOx. Prompt NOx occurs instantaneously even when burning natural gas. Very little prompt NOx occurs during combustion.

Thermal NOx is the predominant NOx generator for gaseous fuels such as natural gas and refinery fuel gas (RFG). Since existing and new heaters burn gaseous fuels instead of fuel oils, thermal NOx formation is primarily addressed in this paper.

2.2 Types of NOx Emissions Control Technologies

NOx control has evolved over the past 40 years. NOx control technologies are generally classified as combustion controls that prevent formation of NOx at the source and post–combustion NOx reduction technologies. Several control methods have been and are continually being developed and used for NOx reduction, such as the following

Combustion NOx reduction:

1. Water or Steam Injection into the Combustion Zone
2. External Flue Gas Recirculation
3. Staged Air Burners (later developed into ULNB)
4. Staged Fuel Burners (later developed into ULNB)
5. Staged Fuel with Internal Fuel Gas Recirculation (IFGR) Burners, referred to as ultra-low NOx burners (ULNB)

Post-combustion NOx reduction:

1. Selective Non-Catalytic Reduction (SNCR)
2. Selective Catalytic Reduction (SCR)

NOx reduction is controlled both at the source and through post-combustion measures, if feasible. A summary of each method is provided in this paper, noting that staged air and staged fuel burners were developed into ULNB technology. ULNBs and SCRs are evaluated in more detail given their better NOx reduction performance relative to the other technologies.

2.2.1 Water or Steam Injection Into the Combustion Zone

Both water or steam injection into the combustion zone reduces the adiabatic flame temperature and reduces the mole percentages of both oxygen and nitrogen in the combustion air. Both of these effects reduce the thermal NOx formation.

Water injection requires a source of water supply, piping, and an injector (atomizer). The water must be effectively atomized to get the maximum benefit from NOx reduction. The latent heat of vaporization and the amount of water will cool the flame temperature and reduce the thermal NOx. However, more fuel is needed to maintain a constant process energy absorption which results in more greenhouse gases being produced and emitted into the atmosphere.

Water injection requires installation costs and continual operating costs. Too much water injection will create flame instability and the burner will flame out. Water injection to control NOx is not typically used in refinery process heaters. ULNBs are better, more efficient, and have no operating costs to reduce NOx.

Steam injection is not widely used for refinery process heaters, but it is used. It, too, requires a source of steam, piping, and injectors. It does not need to be atomized, since it is already in the vapor form. It otherwise works the same way as water injection for NOx control.

Steam injection requires installation costs and continual operating costs. Too much steam injection will create flame instability and the burner will flame out. Steam injection to reduce NOx is used in process heaters in refineries, but not as much as ULNBs. ULNBs are better, more efficient, and have lower operating costs relative to water or steam injection.

2.2.2 External Flue Gas Recirculation (FGR)

External flue gas recirculation takes a portion of the flue gas going to the stack and injects it with the combustion air going to the burner. The external flue gas flow cools the flame temperature and it reduces the mole percent of both oxygen and nitrogen in the combustion air. Both of these effects reduce the thermal NOx formation.

External FGR is measured by the percent of flue gas flow that is recirculated from the flue gas flow to the stack. Too much external FGR will make the flame unstable and go out. The maximum amount of external

FGR for NOx control should be around 20 to 25%. Most applications prefer the external FGR to be less than 20% to ensure the burner flame remains stable.

External FGR is typically used in large single burner package boiler applications and is not generally used in process heaters. However, some process heaters that have a high heat release single burner that requires a forced draft (FD) combustion air fan may use external FGR to minimize NOx formation.

For package boilers, flue gas is taken from a stack connection that is typically close to grade. External flue gas flow is ducted from this stack connection to the inlet of the combustion air FD fan. The FGR flow rate is controlled by a damper in the duct from the stack and a damper upstream of the FD fan. Since process heater stacks are several feet above grade, this type of arrangement is not practical for process heaters.

For the relatively few process heaters that have external FGR, flue gas is taken from a stack connection which is several feet above grade. Insulated ducting from the stack to an FGR fan and ducting from the FGR fan to the burner must be installed for this technology. Even though the installation of external FGR is expensive, it may need to be used to help reduce NOx formation for a process heater with a single, large heat release burner application.

Most process heaters are natural draft with several small heat release burners. Installing external FGR on these heater types is impractical. Since ULNBs use both internal flue gas recirculation and fuel staging, they are more effective in reducing NOx formation and thus are more prevalent in process heaters.

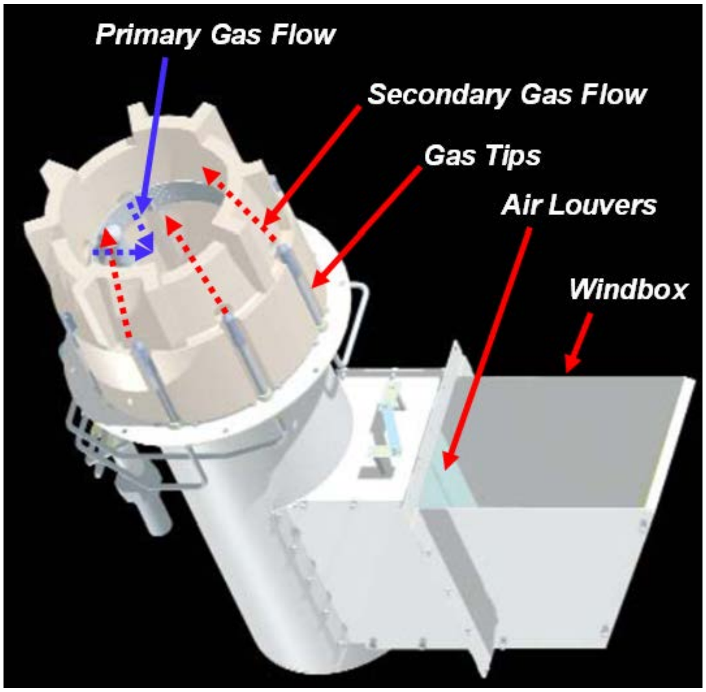
2.2.3 Staged Fuel with Internal Flue Gas Recirculation (IFGR or ULNB)

The current field-proven ULNBs use both staged fuel and IFGR to effectively reduce NOx formation during the combustion process. The total fuel is injected into two sections (primary and secondary) of the burner tile.

The primary fuel flow is about 15 to 25% of the total fuel. It is injected into the throat of the burner through holes in the burner tile. The primary fuel jet acts as an eductor that pulls in flue gas from the heater floor. The primary fuel with the IFGR is mixed with the total combustion air required for the total fuel flow resulting in the flame temperature in the primary combustion region being very low. Also, the mole percentage of both oxygen and nitrogen in combustion air and resulting flue gas are reduced. Even though the excess oxygen is relatively high, the low flame temperature and the reduced mole concentrations significantly reduces NOx formation.

The secondary fuel is about 75 to 85% of the total fuel flow. The secondary fuel is injected up the outside of the burner throat tile and into the flue gas stream from the primary fuel combustion at the exit of the burner throat tile. Due to the secondary fuel jet action, flue gas in the surrounding area is entrained and mixed with the secondary fuel before the mixture reaches the exit of the burner throat. The secondary fuel and IFGR mixture combust up the length of flame, resulting in a longer flame than conventional burners. This is a key feasibility consideration when evaluating this technology in existing heater fireboxes.

An example illustration of primary and secondary flow distribution associated with John Zink's CoolStar ULNB technology is shown in Figure 2-1.



Source: reference 7

Figure 2-1 John Zink CoolStar burner flow distribution.

The ULNBs are self-contained with no moving parts and thus results in low operating costs relative to other NOx reduction technologies. The ULNBs are relatively efficient in reducing NOx formation at the combustion source. They are primarily used for NOx control in refinery process heaters compared to the other types of aforementioned combustion controls.

See Section 2.3 for important design considerations for the feasibility and performance of retrofitting ULNB technology in existing heaters.

2.2.4 Selective Non-catalytic Reduction (SNCR)

With SNCR, ammonia or urea is directly injected into the flue gas steam at a specified flue gas temperature range. The NOx mixes with the ammonia or urea to chemically convert NOx to molecular nitrogen and water vapor.

SNCR technology is not typically used in process heaters due to a narrow flue gas temperature operating range and a relatively low NOx removal efficiency compared to an SCR. Since SCRs are more efficient than SNCR for NOx performance and have a better operating temperature range, they are primarily considered for post–combustion NOx reduction in process heaters.

2.2.5 Selective Catalytic Reduction (SCR)

Similar to SNCR, SCR technology uses ammonia (aqueous or anhydrous) or urea as the reducing agent. Ammonia is injected into the flue gas where it is mixed and flows over a catalyst bed to convert NOx into nitrogen and water vapor. To optimize NOx removal, some residual amount of ammonia remains in the flue gas. This residual ammonia is called ammonia slip.

See Section 2.4 for important design considerations when assessing the feasibility and performance of retrofitting SCR technology in existing heaters.

2.3 ULNB Design Considerations

Specific ULNB design considerations are discussed below. Each of these should be evaluated to determine the technical feasibility of ULNB retrofits and potential limits if ULNBs are feasible.

2.3.1 Spacing and Flame Impingement

Flame impingement (i.e., flame contact with heater refractory, tubes, tube hangars) is a major safety concern, and ULNBs are not feasible if this occurs. Combustion occurring in the visible flame creates high temperatures greater than 2,000°F with very active turbulence. When the flame impinges on tube surfaces, more local energy is transferred by radiation, convection, and conduction through the tube to the process fluid. Flame impingement may cause coke formation on the inside surface of the process tube. This internal coke will continue to build up and insulate the tube from the cooling effects of the process fluid. This can cause the tube temperatures to exceed tube metal temperature limits. If flame impingement continues to occur, the metal temperature will increase and the tube can rupture, releasing process hydrocarbons into the heater’s firebox, risking a fire or heater explosion.

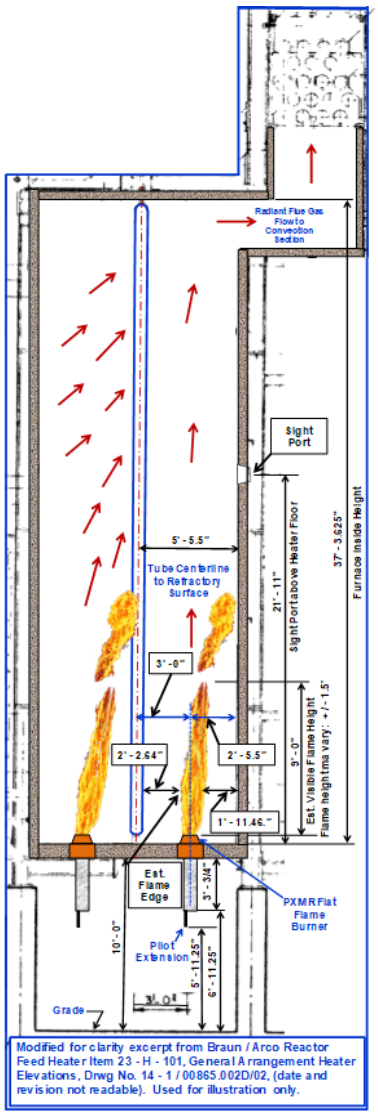
Flame impingement can also overheat heater tube hangers causing them to fail, which may then result in the process tubes falling that will create further impingement on the tubes. In addition, flame impingement on refractory can occur, causing the material to erode and fall, which will then result in overheating of the metal shell. If the local outside surface of the shell gets too hot, thermal expansion will occur. However, the shell around the hot spot is relatively cool and will not expand. The subsequent thermal expansion at the hot spot and the surrounding cooler surfaces can create a buckling effect with the potential of rupturing or cracking the shell. A ruptured shell for integrally supported heaters may even cause the heater to structurally fail.

Any of these conditions presents dangerous working conditions for operations and maintenance personnel working near the heater. Therefore, an ULNB retrofit is not technically feasible if flame impingement cannot be avoided. CFD modeling should be conducted prior to the installation of ULNBs to help determine technical feasibility for each individual heater. Key design factors that can lead to flame impingement are discussed below

2.3.1.1 ULNB Flame Length

Inherently, ULNBs have long flames to stage the fuel and reduce peak flame temperatures (reference 1, references 3 and 4). At high heat releases, the visible flame length may reach 30 to 35 feet or higher depending on operating conditions. At low heat releases, the visible flame length can exceed 10 feet, depending on the ULNB model. API-535 states that natural draft low NOx burners typically have flame heights of 1.5 to 2.5 feet/MMBtu. This can be an issue of technical feasibility because long flames can readily be pulled to the process tubes and refractory walls due to flue gas recirculation currents within the heater.

Figure 2-2 shows an example of flame impingement on process tubes.



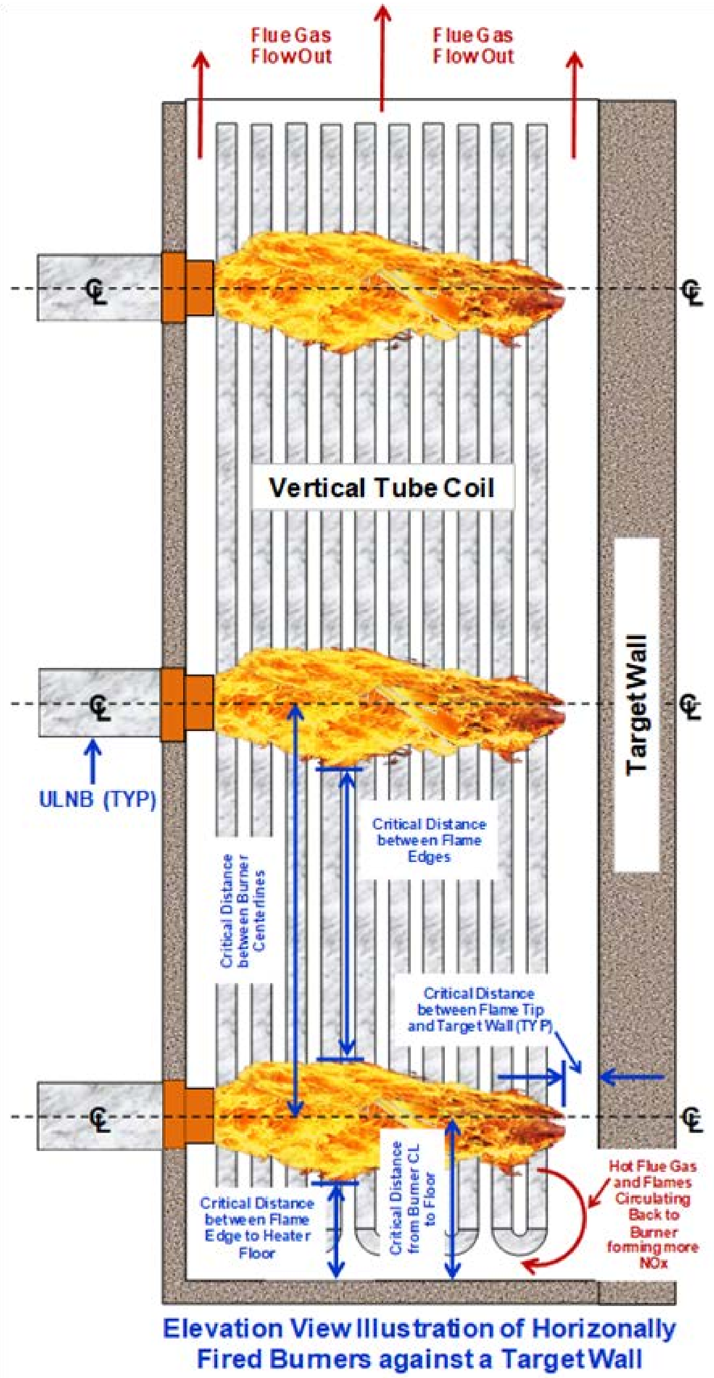
Source: reference 5

Figure 2-2 Illustration of flame impingement on process heater tubes.

In this design, the heater is a natural draft, double fired box heater with a vertical coil. The convection section is offset from the center of the box requiring the radiant section flue gas to go through the radiant tubes and to the convection section. Installing ULNBs with long flames could result in flame impingement, as shown. Further, long flames with certain heater geometries can cause flame impingement on the radiant arch (roof) refractory, the radiant roof tubes, or the convection shock tubes.

Such flame impingement, as described earlier in this document, could result in catastrophic failure. Therefore, flame impingement on the interior components of the heater must be avoided.

Figure 2-3 (also shown earlier as Figure 1-9) shows a burner firing towards a target wall.



Source: reference 6

Figure 2-3 Burner firing towards a target wall.

Installing ULNBs with long flames may impact the target wall, spread out, impinge upon the tubes, and create additional NOx by hot flue gas and flames near the floor circulating back to the burner.

Another example is Figure 2-4 (shown earlier as Figure 1-8), which is a CFD model for a cabin heater with two horizontally opposed firing burners.

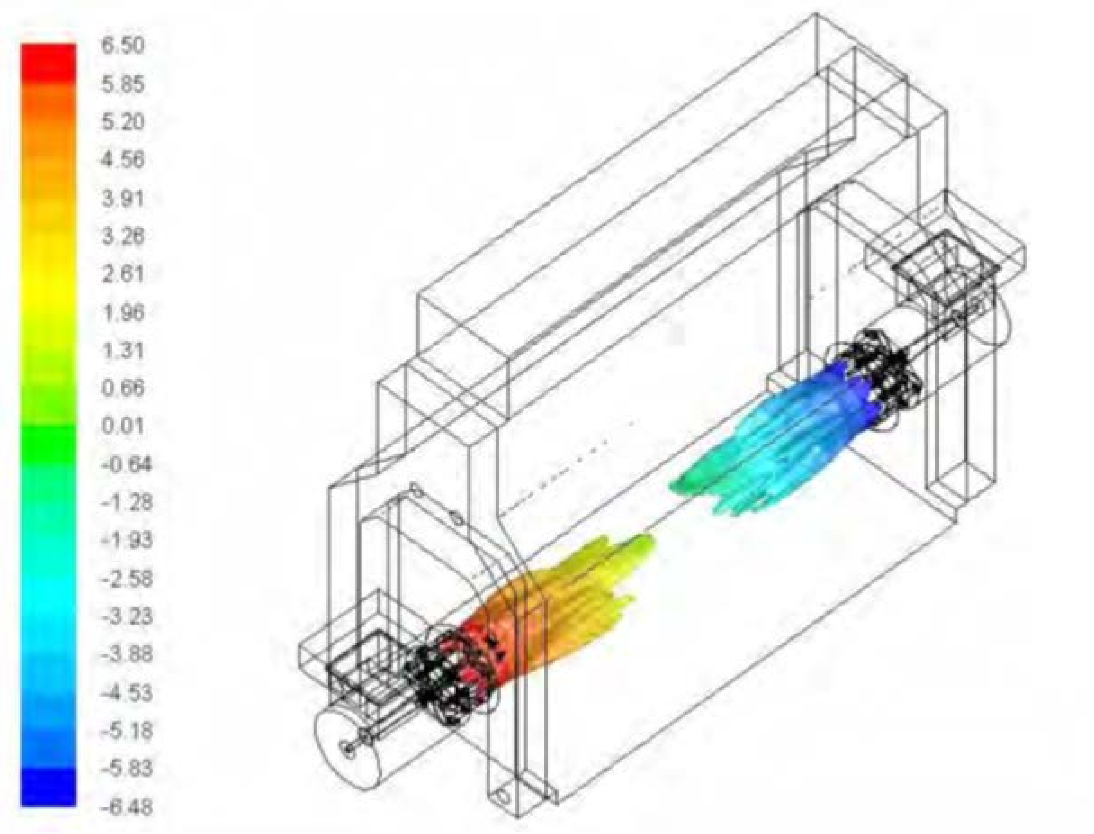


image courtesy of MPC

Figure 2-4 CFD model of horizontal fired cabin heater.

This example shows some space between the flame tips; however, some existing process heater designs may not have this spacing when ULNBs are retrofitted. If adequate space does not exist, then the flames will interact with either other, spread outward, and impinge on the tubes. Even with enough flame tip spacing between the burners, the radiant section internal currents may still pull the flames into the radiant section tubes.

2.3.1.2 Sufficient Spacing

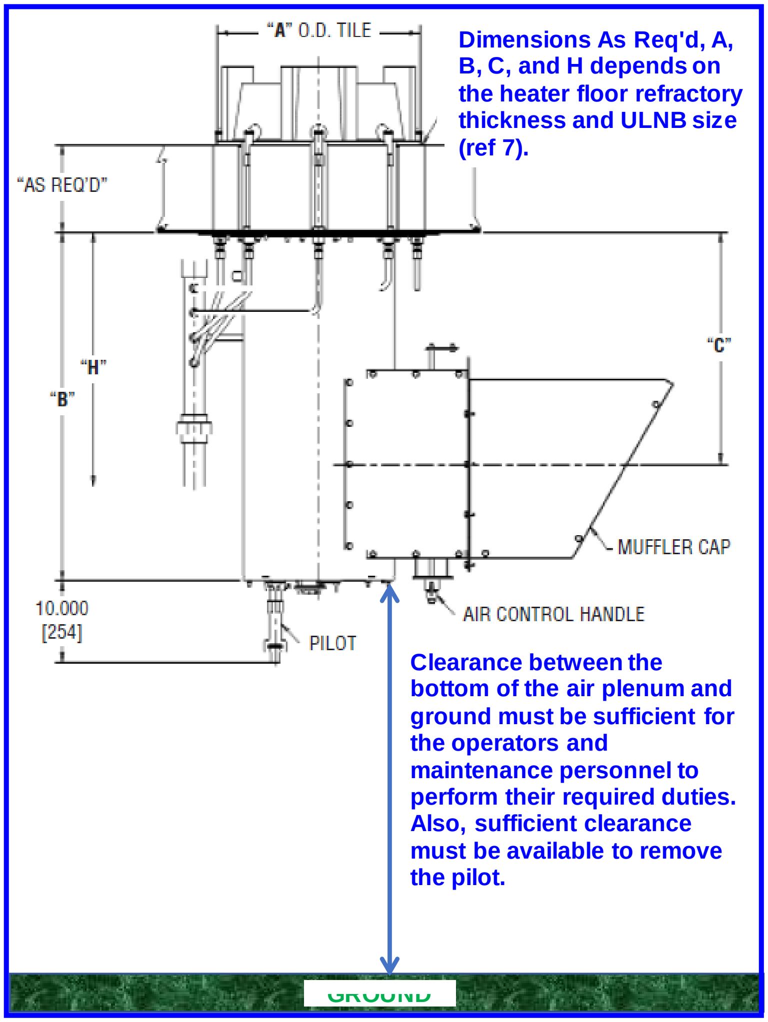
Sufficient spacing is required between the following locations to prevent flame impingement:

- Burners and the radiant tubes
- Radiant refractory side and end walls along with the top of the flame to the arch refractory
- Arch tubes, and / or the convection shock tubes
- Burner to burner

At a minimum, heaters retrofitted with ULNB should follow the same spacing guidelines as a new heater. API-560 Addendum 1 (reference 4) and company-specific heater design documents provide spacing guidelines that should be applied to ULNB retrofits for existing process heaters. Operating experience has shown that the existing API-560 (reference 3) spacing guidelines can be too narrow to avoid flame impingement. The API subcommittee on heat transfer increased these spacing requirements in the approved and to-be-published Addendum 1 of API-560 Fifth Edition (reference 4) to reduce the risk of flame impingement.

2.3.2 Maintenance Accessibility

Operators and maintenance personnel safety is paramount. Some heater floors are too close to the ground, which would force maintenance personnel to perform job responsibilities in unsafe and unergonomic positions for ULNB retrofits. Any ULNB retrofit should have adequate spacing between the bottom of the burner windbox (i.e., air plenum) and the ground to allow operators and maintenance personnel to safely perform their duties. API-560 Addendum 1 requires that the distance between the bottom of the burner air plenum to ground be at least 6.5 feet. Figure 2-5 shows an excerpt from the John Zink CoolStar burner brochure (reference 7) that illustrates spacing requirements for accessibility.



Source: reference 7

Figure 2-5 John Zink CoolStar ULNB excerpt.

The air plenum dimension (B) may be anywhere from 3 to 4 feet long depending on the burner size. For example, if an existing heater floor is only 7 feet from the ground, then clearance between the bottom of the air plenum to the ground would be between 4 and 3 feet. This is insufficient clearance for the operations and maintenance personnel to perform their duties.

During startup, there must be adequate space for an operator to inspect burners and air registers and to properly complete lighting of the pilot(s) from underneath the air plenum. For normal operations, operators inspect the burner air plenums to ensure the pilots remain lit and to inspect the mechanical integrity of components that could affect burner stability or performance. Clearance must be adequate for maintenance personnel to safely remove and clean the burner tips and pilot orifices while the heater is operating. In addition, maintenance personnel have to be able to safely remove the entire pilot, burner gas tips, or flame detection devices while the heater is operating. Operators and maintenance personnel should not be positioned on their knees, backs, or stomachs to perform these tasks.

2.3.3 ULNB Performance Characteristics

Burner manufacturers normally guarantee emissions based upon a single operating condition. Other operating scenarios are not typically guaranteed. However, burner manufacturers may estimate emissions for different expected conditions.

ULNBs manufactured by John Zink, Callidus, and Zeeco, for example, use staged fuel and internal flue gas recirculation (IFGR) principles to minimize thermal NOx formation from combustion. Fuel staging reduces peak flame temperatures, reducing NOx formation. IFGR injects flue gas with reduced oxygen concentrations into the combustion zones, cooling the flame, and reducing NOx formation.

Burner manufacturers generally base their NOx guarantees on the combustion air temperature, fuel gas composition, and excess air (excess oxygen) going to the burner. Refineries have dynamic operating conditions and it is common for process heaters to operate at a wide operating envelope that is inconsistent with the set of conditions used for burner guarantees. For example, and as discussed more in Section 2.3.4.2:

- *Presence of an Air Preheater:* Some high heat release heaters have air preheaters (APH) that raise the combustion air temperature to improve heater efficiency resulting in fuel savings and in lower greenhouse gas emissions. However, NOx formation increases with the use of an APH since higher combustion air temperatures raises peak flame temperatures (reference 1). Therefore, NOx performance limits for heaters with APHs are higher compared to heaters without APHs.
- *Hydrogen and other compositional and heating value fluctuations in refinery fuel gas:* Fuel gas composition is another key parameter impacting NOx performance. For example, high hydrogen concentrations in the fuel gas system increases guaranteed NOx performance because of high combustion temperatures relative to typical fuel gas constituents. Hydrogen in fuel gas systems can vary from 20% to over 60% depending on refinery operating conditions and configurations. Further, any fuel gas constituents that contain chemically bound nitrogen such as ammonia (NH_3), hydrogen cyanide (HCN), or amines can significantly increase NOx formation rates.
- *Changes in oxygen content within heater:* The amount of excess air (i.e., excess oxygen) is controlled to improve efficiency, provides sufficient oxygen for complete combustion at varying operating and ambient conditions, and to ensures flame stability. NOx burner guarantees are higher for heaters with increased concentrations of excess air. Allowing for more excess air into the fire box will increase thermal NOx formation (reference 1). Note, NOx formation increases with excess air up to a maximum value, but enough excess air will eventually reduce peak flame temperatures due to the cooling effect of the ambient air. However, operating with high levels of excess air is inefficient and may jeopardize flame stability. The amount of excess air for optimal operation depends on the heater operation and the manufacturer's recommendation at turndown and low bridgewall temperatures. Therefore, NOx burner guarantees are highly dependent on appropriate levels of excess air.

2.3.4 Heater Operation

Process heater operation is dynamic with several different operation conditions. The excess air required for safe operation will change depending on the heater's operating condition. The heater operating scenarios are the following:

1. Start-up
2. Normal operation
3. Turndown operation
4. Normal shutdown
5. Emergency shutdown

Specific considerations and factors impacting each scenario are discussed below.

2.3.4.1 Start-Up

Process heaters are required to gradually warm the equipment components (e.g. process tubes, tube hangers, refractory, heater shell, etc.) to minimize thermal shock and stresses that may damage the heater. The rate of increase of the flue gas temperature during start–up should be close to 100ºF per hour. At normal operating conditions, the flue gas temperature at the bridgewall is typically around 1,400 to 1,700ºF depending on the heater type. Therefore, the startup time required is generally at 14 to 17 hours; some processes are longer than 24 hours. During the start–up condition, excess air concentrations must be higher to control the temperature in the heater. As discussed above, higher excess air will increase NOx formation, which must be a consideration for the development of NOx concentration limits if they are inclusive of start-up operations.

2.3.4.2 Normal Operations

During normal operations, ULNBs generally perform within the manufacturer's guaranteed limits from approximately 50 to 100% of the burner's maximum heat release and with a bridgewall temperature greater than approximately 1,300ºF. Outside these parameters, excess oxygen increases along with NOx formation. Further, when bridgewall flue gas temperatures are at or below 1,300ºF at a high firing rate, John Zink requires the excess oxygen to be 6% on a wet basis or greater for burner stability. Each burner manufacturer has established NOx guarantees based on 15% excess air.

Excess air is the amount of air over the required amount of air to completely combust the fuel gas, i.e., the excess. Excess air cannot be directly measured. Excess oxygen directly correlates to excess air. Since excess oxygen is measured, excess air can be determined by a mathematical correlation. For example, depending on the fuel gas composition, 15% of dry excess air correlates to around 3% excess oxygen on a dry mole basis.

In practice, low excess oxygen maybe unsafe for all normal operating conditions for new or retrofitted heater designs. For safety, the excess oxygen at the bridgewall should be more than sufficient to ensure that all the fuel is completely combusted in the firebox for all heater operating conditions. A flue gas with excess fuel can occur without sufficient combustion air, which may lead to a heater explosion. The excess oxygen and corresponding NOx performance in the heater depends on the following:

1. Fuel gas composition.
2. Tramp air.
3. Burners Outages and Maintenance.
4. Weather conditions.

Fuel Gas Composition

All refineries combust off gas from the refining process, referred to as refinery fuel gas (RFG). RFG composition can change on a moment's notice. For example, hydrogen concentrations can vary significantly based on operating conditions at other refinery process units. During this transient condition, the amount of excess air required for complete combustion of the fuel can drastically increase. Therefore, the combustion process may not have enough time to respond to the change in RFG, which could result in an unsafe sub-stoichiometric firing condition (i.e., insufficient excess oxygen within the heater for complete combustion). This condition must be avoided at all times, hence the need for flexibility with excess air requirements to accommodate unforeseen process changes. The relationship between excess air fluctuations and NOx performance is described in Section 2.3.3. Refinery operations are dynamic and RFG composition changes are impossible to accurately predict. Therefore, safety considerations require that more excess oxygen is needed to ensure adequate air is used in the combustion process, typically at 3.5% to 4.0% on a wet basis. Given MPC's experience with heater safety, burner manufacturers must guarantee NOx at 3.5% wet excess oxygen at the bridgewall.

Tramp Air

Tramp air is defined as air that enters the heater, but not through the burner (i.e. unintended infiltration air). Typically, sight ports are a common source of tramp air. Operators open sight ports approximately once each shift to view the operating condition of the burners, heater, or process tubes allowing a significant amount of tramp air to enter the heater. Depending on the heater operating condition, these sight ports may be open for around 5 to 20 minutes.

Further, heater shells may not be completely sealed, causing tramp air to enter through these openings. Very old heaters may be bolted together instead of welded, and some existing process heaters will have pressure relief doors at the top of the radiant section. These types of heaters can be a significant source of tramp air. Tramp air will also come from burners taken out of service for cleaning and replacing burner tips, flame impingement caused by a given burner or burners, and heater turndown. Refineries already try to minimize tramp air, but some may still exist which may increase NOx formation.

Heaters are controlled by bridgewall excess oxygen, so tramp air can negatively alter burner performance. Combustion air is designed to enter the heater through the burners. For example, if the bridgewall excess oxygen is 2.5% and the tramp air contributes around 1.5% of this excess oxygen, then the excess oxygen from the ULNB is only around 1%. Low excess oxygen can produce unburned hydrocarbons (UHC) and CO. Depending on firebox temperatures, UHC and CO can mix with tramp air and combust above the main visible flame envelope. This is called afterburning and it will produce its own visible flame that may engulf the process tubes resulting in the overheating of process tubes. As described in Section 2.3.1, this can create an unsafe operating condition.

Burner Outages and Maintenance

ULNB have very small burner tip drillings (can be less than 1/16-inch diameter). Small burner tips are necessary in staged fuel combustion to minimize NOx formation. Even with RFG filters or coalescers, small tips can plug and need to be cleaned to maintain burner performance and stability. In addition, ULNB burner tips may crack over time requiring replacement. Operator and maintenance personnel are able to clean or replace tips while the heater continues to operate. A defective burner is taken out of service by an operator by turning off the burner gas supply and closing the air register. Burner registers are not typically air-tight. Even with the burner air registers closed, around 3 to 5% of the design air flow may still go through the burner becoming a source of tramp air as described above. In addition, the firing rate on the operating burners must increase to produce the same energy release and a constant process operating condition. Air entering the operating burners must increase to ensure complete combustion with no afterburning. Tramp air from the out of service burner register increases bridgewall excess oxygen concentrations. The air registers for the burners in service will be manually opened by the operators to ensure enough air is available for the increase in fuel going through the burners increasing excess air entering the heater. The additional excess air from the out-of-service burner register and the in-service burners will produce more NOx compared to normal operating conditions during this type maintenance event.

In some instances, burners causing flame impingement may be taken out of service for analysis. Burners may be left out of service to improve flame envelopes and to avoid flame impingements. However, as described above, an out-of-service air register may leak excess air, increasing NOx formation.

Weather Conditions

Air entering natural draft burners can fluctuate based on atmospheric conditions. As the atmospheric air conditions change, the pressure differential across the burner air registers can change, inducing more air or restricting air from entering the burners. Therefore, excess oxygen at the bridgewall could increase or decrease depending on the weather conditions, impacting NOx formation and burner performance.

2.3.4.3 Turndown Operation

Turndown operation is the reduction of heater firing relative to normal operations, generally as a response to a decrease in the associated process production rate. Heaters are designed to operate at turndown depending on the market demand conditions, process conditions, start of run (SOR), and end of run (EOR) for a given process unit. Turndown is defined as the actual heat release of the burner compared to the burner's maximum heat release. For example, if the burner maximum's heat release is 20 MMBtu/hr (LHV) and the burner is operating at 10 MMBtu/hr (LHV), then the turndown is (20/10) or 2:1. If the unit turndown is more than 4:1 (25% of maximum capacity), burners may be taken out of service to ensure burner stability. Out-of-service burners result in tramp air going through these burners' air registers as described above, which is expected to increase NOx formation.

Process heaters that service refinery hydrotreating units experience high frequency of turndown operation. After each catalyst change, the fresh catalyst acts as the processing heat source via an exothermic reaction. The process heaters, in turn, often operate at a high turndown, generally up to a 6:1 ratio. As the catalyst ages over multiple years of operation, the catalyst-generated exotherm declines and the process heater correspondingly is fired at a higher utilization to supply additional heat to the process. During high turndown, the NOx levels on a concentration basis will be higher than burner guarantees and are unlikely to meet stringent NOx standards being proposed.

2.3.4.4 Normal Shutdown

For a normal shutdown, heaters should be cooled slow at around 100ºF/hr to avoid excess thermal stress that could damage heater components. During the shutdown process, the heater will be provided additional excess air to help cool the components resulting in higher NOx concentrations, even though the actual mass of NOx emitted is lower due to the decrease in firing.

2.3.4.5 Emergency Operation

During the infrequent occurrence of an emergency operation, the excess oxygen may need to increase which will result in more NOx formation. For example, the process tube metal temperature may exceed its high temperature limit but is not high enough to cause an emergency shutdown. The heater may still operate until a controlled unit shutdown can occur. During this operating period, the heater may experience high turndown for a long duration, which will require more excess air and NOx formation.

2.3.4.6 Emergency Shutdown

An emergency shutdown is a rare event that occurs when a key safety operating parameter is outside of normal limits. For example, if the process fluid flow immediately stops entering the heater, then the heater will automatically shut down for safety purposes. The fuel flow to the burners will automatically shutoff, alarms will sound, and the problem troubleshot to determine the cause and fix. Subsequent restart of the heater will require more excess oxygen going to the burners thus generating a higher NOx concentration in the flue gas.

2.4 SCR Design Considerations

SCR systems have several important design considerations for process heaters. The NOx removal efficiency of SCR depends primarily on the following factors:

1. Ammonia injection distribution
2. Flue gas temperature entering the SCR catalyst
3. Catalyst fouling
4. Catalyst quantity
5. Catalyst age
6. Allowable ammonia slip
7. Heater operations

All these factors are considered by catalyst manufacturers for the heater operating from startup, high turndown, and normal to maximum operations. However, accurately predicting these factors over a several-year operation is difficult, because unforeseen circumstances may occur during operation. Additional detail for each factor is discussed below.

2.4.1 Ammonia Injection Distribution

Ammonia distribution is critical in the proper operation of the NOx reduction in the SCR. The ammonia injection grid (AIG) sprays the reagent into the flue gas where it assumed to be homogeneously mixed with the NOx. To ensure even distribution, a computational fluid dynamic (CFD) model is required for each SCR installation. Without proper ammonia distribution and mixing, the SCR NOx removal efficiency decreases. Theoretical CFD modeling may not be totally accurate in actual applications; therefore, an appropriate margin should be given for the SCR removal efficiency.

2.4.2 Flue Gas Temperature Entering the SCR Catalyst

Flue gas temperatures in excess of 820°F may sinter SCR catalysts and shorten the catalyst life span. API-536 defines sintering as the irreversible loss of active catalyst surface due to high temperatures. High temperature causes the catalyst particles to combine, eliminating micropores and macropores, reducing the catalyst's effectiveness. Some heaters have flue gas temperatures in excess of 820°F. To extend the catalyst life, more catalyst can be added at the SOR, which increases the cost of the installation.

Further, catalyst removal efficiencies can decrease for high flue gas temperature operations. A heater operation with a flue gas temperature at the SOR of 650°F and 850°F at the EOR may only achieve a SCR removal efficiency around 93%, depending on inlet concentration, with a maximum NH_3 slip of 5 ppmvd.

2.4.3 Catalyst Fouling or Masking

API-536 defines masking as a condition where the outer surfaces of the catalyst are covered with foreign material such as refractory dust, outside air dust, ceramic fibers, etc. Dust covers active catalyst surfaces and making the catalyst less accessible for NOx reduction. Accurately predicting catalyst fouling while designing a SCR system is very difficult. To account for masking, SCR manufacturers add more catalyst and increases catalyst spacing to allow the foreign material to pass through. Even with proper design, fouling will increase over time, which reduces the NOx control efficiency; therefore, appropriate margin should be given for the SCR removal efficiency in the establishment of NOx limits.

Further, API-536 defines catalyst poisons as flue gas components that can adsorb onto active catalyst surfaces and rendering them inactive. A list of poisons may be found in API-536, Table K.1, Catalyst Degradation Sources and Mechanisms (reference 2). An example catalyst poison is chromium. Many process heater tubes are made of chromium, which oxidizes over time producing a scale (chromium oxide). This catalyst poison will hinder the SCR performance over time.

2.4.4 Catalyst Volume

NOx reduction is directly related to the amount of catalyst volume in the SCR unit. Also, the volume of catalyst is determined by the amount of NOx and flue gas temperature entering the SCR and the required

NOx destruction efficiency and/or controlled emissions level. Depending on the specific heater operating conditions, the volume of catalyst may become very large requiring significant costs for installation. For example, the flue gas temperature leaving a given heater at the start of run could be around 650°F while at the end of the run the temperature may be over 850°F. These two operating conditions may require two different catalyst types and installation zones, resulting in substantial catalyst and installation costs that may not be economically cost effective to install an SCR.

2.4.5 Catalyst Age

The removal efficiency for SCR systems are calculated at the end of the catalyst life. As the catalyst ages, the active catalyst sites become inactive (refer to Section 2.4.3). For example, the removal efficiency for a new SCR was estimated to be 94.78% at the heater's SOR. At the EOR, the removal efficiency was estimated to be 93.24%. Therefore, the proposed SCR NOx removal efficiency of 95% is too high for the case given above. A NOx removal efficiency of 92% is generally more reasonable for existing process heaters that can be retrofitted with SCRs, depending on the level of inlet NOx.

2.4.6 Allowable Ammonia Slip

To maintain optimal removal efficiency, the ammonia slip must increase over time due to the commensurate increased inactivity of the SCR catalyst. Conversely, if the ammonia slip is fixed, then the NOx removal efficiency decreases. Simultaneously requiring stringent NOx emissions and ammonia limits will significantly decrease the useable life of the catalyst and neither limit may be reliably met.

2.4.7 Heater Operations

As discussed in Section 2.3.4, there are several heater operational variables that can impact the inlet NOx concentration to a SCR reactor. This can result in higher outlet NOx concentration from the SCR system unit especially if ammonia slip is limited to 5 ppmvd. This is especially true during periods of startup and shutdown when additional excess air is sent to the heater.

2.4.8 Additional Considerations

There are additional considerations to assess for a SCR system design.

SCR catalyst installation is critical in achieving the best NOx reduction possible. If the final installed system does not accurately reflect the modeled CFD design, then the NOx removal efficiency will be reduced. In addition, usable space may not be available to install an SCR system and its ancillary equipment considering the amount of required catalyst needed to ensure a high NOx removal efficiency. Section 1.2 shows additional detail on potential space considerations for SCR.

The cost of installing ULNBs and SCRs is also an important factor in retrofitting heaters. This document does not develop installation or loss of revenue costs, but we note that a very costly installation for minimal NOx reduction may not be economically feasible for some existing heaters. Each heater needs to be evaluated individually to determine the cost effectiveness.

The theoretical NOx reduction estimates for a SCR retrofit may not be exact. All engineering calculations have allowable tolerances and design margins. The proposed BARCT limit of 2 ppmvd NOx with a 5 ppmvd maximum NH_3 slip allow for no margin of error or tolerances in the SCR design, especially given possible deviations in heater or burner operating conditions as discussed in Section 2.1.

Finally, accurately measuring low NOx concentrations for compliance with BARCT limits is unreasonable. Individual readings may fluctuate as much as +/- 2 ppmvd or more. Calibrating monitoring equipment to assess compliance with the proposed NOx limit may not be feasible. The NOx monitor may provide different values than a stack test given the low concentrations. Given the high level of monitoring precision required to assess compliance, the proposed BARCT limit of 2 ppmvd is too low.

3 NOx Retrofit Cases for Existing Heaters

Based on the design considerations for ULNBs and SCR systems, it may not be technically feasible to install these controls on every process heater. Therefore, there are four possible scenarios that arise based on a ULNB and SCR feasibility review for each individual process heater:

1. ULNBs may not be safely installed due to flame impingement and/or operations and maintenance personnel's inability to safely execute their duties, and an SCR cannot be installed due to limited available space or excessive installation costs.
2. ULNBs may be safely retrofitted in an existing process heater, but an SCR may not be installed due to limited space or to structural concerns with the heater foundation (if constructed vertically) or at other nearby platform support structures if space if available. Depending on the type of ULNB, required turndown, the fuel gas composition, tramp air, safe operating conditions, and combustion air preheat, the controlled NOx from the installation is normally in the range of 25 to 50 parts per million on a volume dry basis (ppmvd) corrected to 3% excess oxygen.
3. ULNBs may not be safely installed due to flame impingement and/or operations and maintenance personnel's inability to safely execute their duties, but an SCR may be safely installed. Depending on the type of burner in the existing process heater, combustion air preheat, safe operating conditions, excess air (oxygen), tramp air, and the heater's operating mode, the NOx formation entering the SCR could be between 50 to 130 ppmvd. The SCR NOx removal efficiency and any associated outlet NOx limit must consider real-world operational variability and deviations from the theoretical assumptions used in the initial SCR design. With a reliably proven and sustained NOx removal efficiency of 92% for most installations with a higher inlet NOx concentration, the corresponding outlet NOx from the SCR is normally 4.0 to 10.4 ppmvd with a corresponding maximum ammonia slip limit of 10 ppmvd to sustainably meet the underlying NOx limit during normal operations.
4. ULNBs may be safely installed and an SCR may also be safely retrofitted at the existing process heater. From scenario #2 above, the ULNB-controlled NOx concentration is normally 25 to 50 ppmvd corrected to 3% excess oxygen. The SCR NOx removal efficiency and any associated outlet NOx limit must consider real-world variability and deviations from the theoretical assumptions used in the initial SCR design. Given the lower NOx concentration entering the SCR, the sustained NOx removal efficiency may be lower than that in scenario #3. At a 92% control efficiency, the outlet NOx is 2.4 to 4.0 ppmvd with a corresponding maximum ammonia slip limit of 10 ppmvd to sustainably meet the underlying NOx limit during normal operations.

Any emissions limit for NOx, ammonia, and other pollutants that is established for retrofit NOx controls at a refinery heater under scenarios #2 to #4 above must consider the inherent variability in operating conditions that appreciably impact the actual control efficiency on a short-term basis.

SCAQMD's Proposed Rule 1109.1 requires every existing refinery process heater with a design heat release of 40 MMBtu/hour (HHV) or greater to meet 2 ppmvd NOx and 5 ppmvd ammonia slip corrected to 3% excess oxygen on a dry mole basis and on a 24-hour rolling average. These limits and associated averaging period are not proven and/or are infeasible for many existing refinery heaters. For those heaters that can potentially meet these emission limits under ideal conditions, the limits as proposed provide no margin of safety for compliance with respect to the inherent operational variability that is experienced by refinery process heaters.

In conclusion, process heaters in the refining industry have several unique considerations for ULNB and SCR retrofits. There are many unique heater configurations that can significantly alter the feasibility of ULNB or SCR. Each heater needs to be evaluated independently for feasibility. Not all heaters can be safely equipped with ULNBs and SCR due to flame impingements, safe operations, inadequate space, etc. Given these considerations, the Proposed Rule 1109.1 emissions limit of 2 ppmvd NOx with 5 ppmvd ammonia slip for most refinery heaters is too stringent to allow for the needed operational flexibility and will be impossible for existing process heater retrofits to continuously comply.

4 References

1. American Petroleum Institute (API), API-535, Burners for Fired Heaters in General Refinery Services, Third Edition, May 20, 2014, API Publishing Services, 1220 L Street, NW, Washington, DC.
2. American Petroleum Institute (API), API-536, Post-Combustion NO_x Control for Fired Equipment in General Refinery Services and Petrochemical Services, Third Edition, API Publishing Services, 1220 L Street, NW, Washington, DC.
3. American Petroleum Institute (API), API-560, Fired Heaters for General Refinery Service, Fifth Edition, February 2016, API Publishing Services, 1220 L Street, NW, Washington, DC.
4. American Petroleum Institute (API), API-560, Fired Heaters for General Refinery Service, Fifth Edition Addendum 1 (balloted and approved), publication date pending, API Publishing Services, 1220 L Street, NW, Washington, DC.
5. Braun / Arco Drawing Excerpt, Reactor Feed Heater, General Arrangement Heater Elevations, Drwg Number 14-1 / 00865.002D/02, REV 3, Date 1993.
6. Foster Wheeler Corporation (FW) Drawing Excerpt, Direct Fired Heater General Arrangement Cross Section, Drwg Number 136-1-6-2D, Date 1960.
7. John Zink Brochure, CoolStar Burner, The Industry's Most Compact Ultra Low-NOx Gas Burner, No. 06-1940, John Zink Company, 2006.
8. Marathon Petroleum Company, SP-45-01, Fired Heater Design, Effective Date: March 20, 2016.
9. Wilson, L.D., Illustrations Drawn by L.D.W. for Operator and Engineering Training Programs, Unpublished.

ATTACHMENT C

Technical Memorandum

To: Marathon Petroleum Corporation (MPC)
From: L. David Wilson
Subject: Review of NEC and FERCo Engineering Reports for Refinery Process Heater NOx Reductions
Date: January 29, 2021

Norton Engineering Consultants (NEC) and the Fossil Energy Research Corporation (FERCo) evaluated the feasibility and implementation of NOx control technologies for the South Coast Air Quality Management District (SCAQMD). The studies from NEC and FERCo are expected to be used to assess the feasibility of SCAQMD Best Available Retrofit Control Technology (BARCT) NOx emission controls and associated limits for many refinery emission sources. While the studies are informative, there are several technical concerns for ultra-low NOx burners (ULNB) and selective catalytic reduction (SCR) that are either not addressed or that are not addressed appropriately for refinery process heaters. A technical review of each study as it relates to refinery process heaters is provided in this memorandum.

These comments are based also on a detailed evaluation conducted of technical feasibility issues associated with NOx emissions reductions at existing refinery process heaters. This evaluation is provided in a report to MPC under separate cover and provides important documentation for the comments made in this memorandum.

1.0 Review of NEC Report Regarding Process Heater NOx Controls

In general, the Norton Engineering Consultants' (NEC) report (reference 7) was well written and adequately addressed current and emerging control technologies to reduce NOx formation. However, the report excludes logical and important conclusions which the data supports, as follows:

1. Not all existing process heaters can be safely retrofitted with ultra-low NOx burners (ULNBs) to avoid flame impingement on the existing heater process tubes, tube hangers, or refractory surfaces. Flame impingement on process tubes will overheat the tubes, may result in a tube rupture, and a firebox explosion. In summary, the report does not recognize the key critical issues:
    a. The report recognizes that ULNBs produce longer flames but does not address solutions for existing heaters' radiant sections that are too short to accommodate these longer flames.
    b. Additional costs are necessary to install and maintain a fuel conditioning system, such as filters/coalescers, stainless steel piping, electrical and instrumentation, controls, foundations, etc. Also, the report does not address the costs associated with periodic burner tip cleaning and tuning.

   c. The report identifies burner spacing considerations but fails to offer solutions when proper burner spacing is not possible to prevent flame impingement in an existing heater.
   d. The report does not address the cost associated with eliminating tramp air commonly found in decades-old existing heaters. Very old heaters may be bolted together and will, essentially, require a heater rebuild to eliminate tramp air.
   e. The report recognizes that exceeding the API-560 (reference 3) and API-560 Addendum 1 (reference 4) standards for floor heat flux density or volumetric density will increase NOx emissions from ULNBs but fails to state that these parameters need to be considered in retrofitting ULNBs. The report state that exceeding these parameters' values will limit the effectiveness of ULNBs in retrofit applications but draws no conclusions for NOx reduction effectiveness associated with this exceedance. The report provides no remedies if the heat flux or volumetric density deviates from API's safe design criteria.
   f. The report recognizes that heater turndown must be considered in retrofitting ULNBs but does not identify remedies to the issues that turndown presents for NOx control and related performance.
   g. The report reviews emerging technologies that have not been proven or even installed in the field. For example, ClearSign has installed very few burners with limited applications for very low heat releases in the field, while John Zink SOLEX burner is still in the testing phase with no installations in the field. Emerging technologies such as these reviewed that have not been proven in the field or still on the testing stand should not be considered in setting a NOx emission limit that is intended to be applied as a retrofit for every type of refinery process heater.
2. Not all existing process heaters can be retrofitted with SCRs due to space limitations and/or excessive cost constraints. The report states on page 23, *"Existing units are generally space constrained and locating the SCR and ancillary equipment (i.e., ammonia/urea tanks, pumps, vaporizer, piping, etc.) within the available on-site plot space or remotely is an important operational consideration."* This statement fails to identify recommendations or the cost effectiveness of installing an SCR if the spacing is constrained for an existing heater in an already congested process operating area.
3. All existing process heaters must be individually analyzed to determine if ULNBs and SCR with its associated ancillary equipment can safely, physically, and economically be installed.
4. The report mentions many issues for installing ULNBs and SCRs that must be considered but fails to acknowledge that these considerations effectively makes retrofitting existing process heaters with these technology infeasible on a technical and/or cost basis.
5. The report mentions SCR reliability at levels greater than 10 ppmvd and notes limited information is available for SCR reliability at less than 10 ppm. It does not reach the logical conclusion that a universal solution is unavailable that can be applied to all existing heaters and that can sustainably meet the BARCT limits as currently proposed.

Additionally, NEC's primary conclusions in the report are not indicative of the data and presentation provided:

1. NEC concludes that the NOx limit of 2 ppmvd (assumed to be corrected to 3% excess oxygen) is technically achievable for all existing process heaters. This conclusion ignores their own statements that limited technical information on NOx removal is available below 10 ppmvd to determine SCR reliability at these emission levels.
2. NEC concludes that the ammonia slip limit of 5 ppmvd is technically achievable for all existing process heaters. This conclusion neglects statements in the report that overtreating with ammonia may be necessary to achieve SCR NOx removal if the optimum temperature window is not achievable. The report addresses installing an ammonia destruction bed to limit the NH3 slip. However, the report does not address the performance of the ammonia destruction bed, its disposal requirements, and an associated cost effectiveness analysis to determine feasibility.

In summary, NEC's report, as reviewed and critiqued in this memorandum, demonstrates that a single approach for establishing NOx removal efficiencies and emission limits at every type of existing, older process heater at refineries is not technically feasible or practically achievable.

The NEC report centers on the use of ULNBs and SCR technology for NOx emissions reduction. Technical challenges and considerations for these installations and related performance issues that are not identified or need clarification are provided in the following sections.

1.1 Review of ULNB Information in Section 3.1 and 3.3 of NEC Report

NEC's report identifies NOx control technologies that limits NOx formation from combustion and reduces NOx post-combustion. The control technologies that limit NOx formation from combustion in the NEC report are fuel switching, external water or steam injection into the combustion process, external flue gas recirculation (FGR), and low NOx (LNB) and ultra-low NOx burner (ULNB). After reviewing the control technologies to limit NOx formation in the combustion process for existing process heaters, the NEC report recommends using ULNB.

Technical concerns in the NEC report with respect to the feasibility (i.e., safety) and performance of ULNB technology are provided below.

Flame Impingement - NEC recognizes that ULNB have longer flames compared to conventional burners, which may result in flame impingement on heater tubes, tub hangers, or refractory for ULNB retrofits. The NEC reports states on page 12, *"A radiant section that is firing with ULNB needs to be long enough to avoid flame impingement on internal surfaces."* However, the report does not address the consequence if the radiant section is not sufficiently tall enough to avoid flame impingement. Flame impingement is a critical safety concern. Such impingement can rupture heater tubes by overheating the metallurgy. Flame impingement may also break heater tube hangers, which may cause the process tubes to fall and create further impingement. Any of these scenarios may lead to a catastrophic explosion in the firebox, which is clearly unacceptable. In addition, impingement on refractory can cause the material to erode and fall from the heater shell overheating the metallurgy. The shell may crack, which presents dangerous working conditions for operations and maintenance personnel working near the heater. Therefore, an ULNB retrofit is not technically feasible if flame impingement cannot be avoided. CFD modelling and adherence to the API standards and company-specific heater design standards should be conducted prior to the installation of ULNB at a given heater to determine feasibility.

Air Preheaters – Table 3.1-1, which excerpts Table 13 of API-535 (reference 1), provides typical NOx emissions when burning a gaseous fuel. It states that the NOx levels with ULNB could be 10 ppmvd firing natural gas or 20 ppmvd with refinery fuel gas (RFG). NEC appropriately notes that this table in the API document was produced from a test furnace operating under ideal design and operating conditions and is not from an operating heater at a refinery. NEC's report also states that these low values are rarely achievable in an operating heater and the actual NOx could be as much as two times (40 ppmvd) that of the idealized Table 3.1-1 number. However, NEC does not consider the performance impact of refinery heaters with air preheaters. NOx concentrations from heaters with air preheaters typically are higher due to hotter flame temperatures, which may hinder a heater's ability to comply with associated BARCT limits.

Heat Flux and Volumetric Heat Density - NEC discusses the concerns for ULNB retrofits for heaters with high floor heat flux or high volumetric heat density. ULNB performance would be hindered, but no specific performance levels were listed. Careful consideration should be given to ULNB retrofits for these types of process heaters and associated emission limits. Further, no remedies were provided for heaters that may exceed the API-560 heat flux or volumetric heat density standard.

Fuel Conditioning - NEC note that ULNBs typically use fuel filters/coalescers to minimize plugging of burner tips as they are smaller than conventional burners. Even with proper fuel conditioning, ULNB burner tips can still become plugged requiring removal of the burner for online maintenance. Burner removal is likely to degrade ULNB performance because air registers for removed burners commonly leak air (also known as tramp air). During online maintenance, the other remaining burners in service must fire at higher rates, which increases bridgewall oxygen and NOx formation. While burner maintenance may not be a frequent occurrence, this operating scenario must be considered for the establishment of limits for ULNB installations on natural draft heaters. Further, these maintenance costs should be considered for any cost effectiveness analysis for ULNB. Also, piping downstream of the filter/coalescer sets may need to be upgraded to stainless steel to prevent the formation of rust and scale associated with carbon steel piping and, therefore, minimizing fouling of the burner tips. The upgrade in downstream ULNB piping was not considered by NEC.

Tramp Air - Many older vintage heaters were bolted together as opposed to welded or have large pressure relief doors at the top of the radiant section, which results in significant tramp air infiltration increasing thermal NOx formation. Tramp air must be independently evaluated for the establishment of limits for ULNB retrofits. In addition, NEC does not recognize the cost associated with minimizing tramp air to improve ULNB performance, which could be significant for aged heaters. In some cases, a cost a full heater rebuild may be necessary to resolve tramp air issues.

Burner Spacing - NEC mentions technical issues with burner spacing for ULNB, but they do not consider horizontal flame clearance between two opposed horizontal firing burners or between horizonal firing burners and a target wall. This can result in flame impingent and the associated issues discussed above. In addition, the clearance concerns above can change flue gas recirculation patterns creating higher flame temperatures and more NOx formation, degrading the ULNB performance.

Maintenance Accessibility - NEC fails to consider burner accessibility if a retrofit project requires lowering of the floor to accommodate a longer flame length. Doing so may cause heater floors to be too close to the ground, which would force maintenance personnel to perform job responsibilities in unsafe and unergonomic positions for ULNB retrofits. There must be sufficient clearance from the bottom of the burner air plenum to the ground to pull out the pilot assembly while the burner is in operation.

Emerging Burner Technologies - NEC reviewed emerging burner technologies including the ClearSign Core and John Zink's SOLEX. While the testing results for these burners appear promising, they are still considered to be emerging technologies and are not commercially proven by the refining industry. NEC does not unequivocally state that these emerging technologies are not commercially proven and are not viable alternatives to existing ULNBs. Since they are not proven technologies, they should not be considered these technologies should not be considered as viable alternatives to well-establish ULNBs nor should they be used to establish BARCT limits.

Flameless Combustion Technologies - NEC stated that flameless combustion technologies "may… not be possible" for existing heater retrofits. The technology has a very limited application and should not be a viable alternative to conventional ULNBs.

ULNB Feasibility – Table 3.3-1 of the NEC report seems to suggest that ULNB technology is technically feasible for all existing process heaters. Each heater must be evaluated ULNB technical feasibility individually to determine conformance with API and company-specific safe design standards and practices.

ULNB Turndown Performance with Air Preheaters – Table 3.3-1 may not be representative of ULNB performance in turndown conditions for heaters equipped with air preheaters. More typical ULNB performance for this scenario is 40-45 ppmv @3% O_2.

In summary, the NEC report does not address what happens when an existing heater cannot install ULNBs without resulting coalescing long flames, flame impingement on heater internals (i.e., tubes and refractory surfaces), and/or does not allow for safe operation and maintenance. Additionally, each existing heater should have the following technical evaluations performed to determine if ULNBs are safe to install to avoid flame impingement and allow the heater to be safely operated and maintained pursuant to API and company-specific design standards:

1. Determine the floor heat flux and volumetric heat density and ensure they comply with API-560 Addendum 1 (reference 4).
2. Determine the spacing between flame height and roof tubes, convection shock tubes, and roof refractory to ensure no flame impingement can occur on these surfaces.
3. Determine the spacing between the burner flame envelope and tubes and refractory surfaces to avoid flame impingement on these surfaces.
4. Determine the spacing between burners to ensure the flames do not coalesce, grow, and become unstable.
5. Determine the spacing between flame tips for horizontal firing burners to avoid flame intertwining and possible tube flame impingement.
6. Determine the spacing between the flame tip and the target wall to avoid flame impingement on the wall that may result in tube flame impingement and higher NOx formation.
7. Perform a computational fluid dynamic (CFD) model to help determine whether flame impingement will not occur with the retrofitted design.

1.2 Review of SCR Information in Section 3.2 and 3.3 of NEC Report

The NEC report reviews three post-combustion NOx removal systems: selective non-catalytic reduction (SNCR), low temperature oxidation (LoTOx), and selective catalytic reduction (SCR). SNCR technology is almost never used in process fired heaters due to turndown issues and geometrical considerations and thus is not a viable option for process heaters. LoTOx is not intended for gas-fired refinery process heaters and has no commercial installations. Therefore, NEC evaluated SCR in more detail.

Technical concerns not addressed or that require clarification in the NEC report with respect to the feasibility (i.e., safety) and performance of SCR technology are provided below.

Turndown - NEC did not mention that turndown for heaters with ULNB can be a concern for SCR performance because the flue gas temperature entering the reactor will decrease lowering the NOx removal efficiency. This must be a consideration for the establishment of limits for heaters with SCR.

Varying Flue Gas Temperatures - The flue gas temperatures for some heaters vary significantly from the start of run (SOR) to the end of run (EOR) between maintenance turnaround activities. Designing a catalyst bed to maintain an optimal NOx control efficiency for varying temperatures throughout the entire operating range from SOR to EOR must be considered for the establishment of limits for each individual heater with SCR. A higher temperature will affect (lower) NOx removal efficiency, and each heater must be individually evaluated to determine SCR effectiveness at expected flue gas temperatures.

Allowable Ammonia Slip - Higher levels of ammonia slip (i.e. 10 ppmvd) is needed to maintain NOx removal efficiencies at various operating conditions that deviate from theoretical and optimal conditions used in the SCR design control efficiency calculations. This is especially important if high control efficiencies are desired. NEC does not address the intrinsic relationship and flexibility needed with ammonia slip to optimize NOx removal.

CFD Modeling and Limit Flexibility - Even with proper CFD modeling and SCR system design, there can still be improper mixing degrading the NOx removal efficiency. Reasonable tolerances should be incorporated in NOx and ammonia slip limits. NEC does not address this inherent practical issue.

Unexpected Catalyst Fouling and Limit Flexibility - Although SCR systems are designed to operate at the guaranteed performance at EOR operation, predicting the actual operating condition of a heater for a five-year period is difficult. For example, it is impossible to predict dust fouling from refractory or heater tube scaling as the materials deteriorate over time. Marathon has observed the fouling of SCR catalyst on a process heater within just 20 months of operation, reducing the NOx control efficiency by 8% and causing a 9-day unplanned outage. Given this uncertainty, any NOx or ammonia slip limits must not be too stringent to prohibit heater operation at EOR operations.

Physical Space Constraints – NEC discussed space constraint considerations for SCR operation but not the clear consequence of not physically accommodating SCR. If a company cannot physically accommodate an SCR at an existing heater, it is not technically feasible.

1.3 Review of NEC's Conclusions in Section 4.1 of Report

Section 4.1 of NEC's report assesses the feasibility and performance of the combined ULNB and SCR technologies relative to the BARCT limits in the Proposed Rule 1109.1. Key technical concerns in the NEC report with respect to these conclusions are provided below.

Reliability and Performance – NEC's belief that a 2 ppmvd limit is technically feasible for all refinery process heaters is unsubstantiated. NEC states that "limited information is available for SCR reliability at sub 10 ppmv NOx emission levels." In addition, Figure 4.1-1 shows that most emissions data are well above the 2 ppmvd threshold. Therefore, it is illegitimate to propose a 2 ppmvd limit as it has not been thoroughly demonstrated in practice, especially given the various heater and burner configurations in place at petroleum refineries. Generally, the refining industry has demonstrated that a 92 to 94% NOx reduction in a single catalyst bed with NH3 slip up to 10 ppmvd is feasible in practice. Therefore, for heaters where it is technically feasible to install SCR, corresponding limits must provide adequate flexibility as opposed to a standard applied broadly across the industry. The final SCR outlet NOx concentration is dependent on many factors including the burner performance, so it must be evaluated in a heater-specific basis and with CFD modeling to ensure good mixing and no bypassing or channeling. This is especially important for heaters that where it is technically infeasible to install ULNBs and should be taken into consideration for establishing BARCT limits, since the NOx concentration to the SCR is higher than with ULNB.

Averaging Time – NEC recommends that limits for SCR units should be based on a rolling 24-hour average. However, even a 24-hour averaging period still may not provide sufficient time to allow for startup periods, outages in the ammonia injection grid, or unforeseen operation upsets. Averaging times should be similar to limits for fluidized catalytic cracking units (FCCUs) on an annual and weekly basis.

Performance Variation by Heater Classifications – Table 4.1-1 classifies equipment by the design firing rate (MMBtu/hr). However, this is insufficient and not a reasonable comparison. Heaters in the refining industry have different process fluids, tube materials, shapes, sizes, burner orientations, firing conditions, tube orientations, and draft types. The report does not recognize these differences and how this impacts the feasibility of meeting the proposed BARCT limits and ULNB/SCR performance considerations. The table incorrectly assumed that ULNBs could safely be retrofitted in all existing process heaters. Each heater has to be evaluated independently to determine if ULNBs could be retrofitted in an existing process heater without flame impingement and will allow operations and maintenance personnel to safely execute their responsibilities. This is a logical conclusion that is not stated in the NEC report.

1.4 Conclusions

After a thorough review and comments on NEC's NOx BARCT Analysis Review (reference 7) report, the NOx limit of 2 ppmvd and a corresponding maximum ammonia slip of 5 ppmvd corrected to 3% excess oxygen was not reliably proven in the NEC report. These values do not allow operating flexibility and will be impossible to continually met by retrofitting exist process heaters with ULNBs and SCRs, even if it was feasible to complete such retrofits. These low limits may be difficult for even newly designed process heaters to meet when first put in service and continually operating for several years under ideal conditions.

Not all existing process heaters can be safely retrofitted with ULNBs and SCRs due to flame impingement, safe operations, and inadequate space for installation. The data analysis in the report and the data presented in Figure 4.1-1 do not support these very low limits as being reliable and achievable for all existing refinery process heaters.

2.0 Review of FERCo Study Regarding Process Heater NOx Controls

In general, the Fossil Energy Research Corporation (FERCo) report (reference 5) was well written in its description of theoretical calculations for sizing SCR units and their operations. The SCR examples were idealized and do not represent most existing operating heaters. The report does not adequately cover feasibility and performance of retrofitting field-proven ULNBs in existing process heaters; it was focused primarily on SCRs.

FERCo identifies four unique issues in page 1-1 of the report that are important to address in this memorandum for clarification, as follows:

1. *"Implementation timing given that typical maintenance turnarounds take place every 5 years, and the planning for acquisition of both capital and construction labor are concluded at least 2 years*

prior to the event." A 5-year turnaround cycle is not typical for all units within the refinery. Some units may be longer at 6 to 10 years. Any potential SCR installation should account for the actual turnaround cycle for a given unit in the refinery. The example in Table 5–1 is based on 40,000 hours, equivalent to 4.56 years and not the stated 5-year turnaround. If the unit must be shut down and the catalyst changed before its normal turnaround cycle, then the loss of revenue should be considered in the overall economics of installing an SCR.

2. *"Space can be limited in a refinery due to adjacent equipment and the need for maintenance access roadways and equipment staging areas. SCR reactors and ancillary equipment require adequate space for installation. These space limitations may require some creative engineering and can have an impact on retrofit costs."* This statement is factual; however, it suggests that with creative engineering an SCR may be installed effectively anywhere with extra costs. In reality, space may not be available to install an SCR and all of its ancillary equipment. On page 5–1, FERCo recognizes this fact: *"Until BARCT limits are established and refineries and their associated engineering companies can seriously look into retrofits, it is difficult to say what fraction of the units may not be candidates for SCR retrofits."* Furthermore, the SCR units may be quite large and heavy with massive foundations. These foundations plus all the other associated installation costs need to be considered in the overall economic analysis.
3. *"NOx averaging times to accommodate the anticipated variable NOx outlet values, when attempting to meet low BARCT limit."* The FERCo report does not address this issue in detail. The Norton report (reference 7) addresses the issue and recommends the averaging time be increased to 24 hours. However, even a 24-hour average will not always be sufficient to address major operating deviations or maintenance. For example, if the ammonia injection grid or system malfunctions, 24 hours will not be enough time to repair it.
4. *"Generation of particulate matter due to residual NH_3 from SCR and concentrations of sulfur compounds in the flue gas from the combustion of refinery fuel gas."* The report stated that these reactions occur below 500°F. If the heater system has a combustion air preheater (APH) and an induced draft (ID) fan, the ammonium sulfates and bisulfates will deposit on the APH and the ID fan internal surfaces downstream of the SCR. Additional particulate matter will also exit the stack as emissions. Depending on the quantity of deposits, the heater may be prematurely shutdown to clean the APH and ID fan. The loss of revenue for this outage should be considered in the overall economic analysis of installing an SCR. If the system does not have an APH, then the particulate matter will form outside the stack when the flue gas is cooling to ambient temperatures.

The FERCo report identified some significant conclusions listed on page 6-1:

1. *"Refineries may be space-challenged to install SCRs on some devices."* To be clear, the space may be too challenging to install SCRs at all.
2. *"Further lowering NOx emissions could increase particulate emissions…"* This fact needs to be considered in determining NOx emission limits.

3. *"The EPA NOx costing model could be improved to better reflect refinery SCR systems, most notably the methodology to estimate the required catalyst volumes based on current catalyst technology that is available."*
4. *"Existing refinery SCR systems will need to be evaluated on a case-by-case bases to see how they can be upgraded to meet the new BARCT limit, or if major modifications are necessary."*

The FERCo report ignores the following logical and key conclusions that should be made:

1. Not all existing process heaters can be safely retrofitted with ULNBs to avoid flame impingement on the existing heater process tubes, hangers, or refractory surfaces. The report fails to review current and proven ULNBs and instead only reviews non-field proven emerging technologies which should not be considered as BARCT until they are field proven for all applicable installations.
2. All existing process heaters must be individually evaluated to determine if ULNBs can safely be installed without creating flame impingement on heater internal components. The report fails to even mention the possibility of flame impingement, which is a critical technical feasibility concern.
3. A NOx limit of 2 ppmvd (assumed to be corrected to 3% excess oxygen) is not technically achievable for all existing process heaters.
4. The associated ammonia slip limit of 5 ppmvd is not viable for all existing process heaters to provide the flexibility needed to optimize NOx emissions over a heater's operating cycle.

In summary, FERCO's report, as reviewed and critiqued in this memorandum, demonstrates that a single approach for establishing NOx removal efficiencies and emission limits at every type of existing, older process heater at refineries is not technically feasible or practically achievable.

The FERCo report centers on the use of ULNB and SCR technology for NOx emissions reduction. Technical challenges and considerations for these installations and related performance issues that are not identified or need clarification are provided in the following sections.

2.1 Review of Relevant Host Equipment in Section 2 of FERCo Report

FERCo's report presented a refinery process overview and some major equipment types. In this review, only the existing refinery process heaters were reviewed and commented on here.

Operational Variability - The FERCo report showed a graph of refinery process utilization: Figure 2-5, Four – Week Refinery Percent Utilization: West Coast Refineries. This graph shows that the utilization fluctuated from a minimum of 75% to a maximum of 100% with average of around 89% for the period of 1995 to 2019. The graph is highly misleading inasmuch as FERCo infers that "key portions of a refinery" such as heaters operate at steadily high duties at all times. This is not the case for many process heaters depending on the service that they are in. Individual heater utilization and turndown will differ from the plant utilization shown in the graph and the heater duty varies based on many operating variables including process fluid temperatures and flowrates and dynamic fuel gas composition. This graph only shows that the consumers on the west coast have a high demand for transportation fuels and the refineries supply this demand, but it does not show individual heater utilization within the plant.

Factors Affecting NOx Control Cost – FERCo identifies and defines their concept of direct and indirect costs but does not detail the components considered or excluded in the cost analysis. The lists below present some of the major cost items, not inclusive, with retrofitting existing process heaters with ULNBs and SCRs. These lists do not differentiate between FERCo's "direct or indirect cost" since all of these costs are associated with a potential retrofit:

ULNB:

1. Purchase complete ULNBs assemblies.
2. Factory performance testing of ULNBs.
3. Installation: remove the existing burners and modify the floor to accept the ULNBs, equipment rental, labor, etc.
4. New instrumentation, installation, and control: flow meters, flame scanners, pressure transmitters, temperature transmitters, etc.
5. New filter / coalescer sets, piping, and installation. Piping downstream of the filter coalescer set is the more expensive stainless steel piping to avoid internal scale that would go to the UNLBs and plug the burner tips.
6. New combustion air ducting especially for a balanced draft heater with a combustion air preheater.
7. Engineering and administrative costs for retrofit, e.g., computational fluid dynamic (CFD) modelling.

SCR:

1. Purchase complete SCR modules and catalyst.
2. New flue gas ducting with internal installation and support.
3. New foundations to support SCR modules, catalyst, and ducting from the heater to the SCR.
4. Ammonia skid, foundation, and installation.
5. Ammonia storage tank, foundation, and installation.
6. New piping for ammonia injection: the ammonia injection grid (AIG).
7. New instrumentation, installation and control.
8. New electrical connections.
9. Platforms.
10. Lighting.
11. Engineering cost for retrofit.
12. Installation: equipment rental, labor, etc.
13. New control logic and installation.

14. Catalyst disposal cost based on 5-year cycle instead of 10-year cycle because of the very low, proposed NOx emission and NH3 slip limits.

New Induced Draft (ID) Fan

1. Purchase cost of ID fan.
2. Factor mechanical and performance test.
3. Ducting to ID fan from the SCR and from fan to the stack.
4. Electrical equipment, connections, and upgrade to electrical system.
5. Foundations and installation.
6. Dampers and / or variable frequent drives.
7. Lighting.
8. Engineering cost for retrofit.
9. New control logic and installation.

The above are just some of the cost considerations to retrofit ULNBs and SCRs for existing process heaters and is not inclusive of all the equipment needs for a given installation based on heater-specific circumstances.

Production Loss - Since retrofitting existing heaters with ULNBs and SCRs is time-consuming and may occur outside the regular turnaround schedule, the turnaround time to accommodate this work will likely result in direct losses in production and opportunity. If the turnaround is extended or occurs outside of planned outages due to the retrofit, then the cost associated with a loss of production should be considered in the overall cost effectiveness of the retrofit.

2.2 Review of ULNB Information in Section 3.1 of FERCo Report

Technical concerns in the NEC report with respect to the feasibility (i.e., safety) and performance of ULNB technology are provided below.

Performance Level - FERCo's report states at page 3-1, *"Ultra Low NOx Burners (ULNB) are burners with NOx emissions less than 10 ppm when firing refinery fuel gas."* Also, the reported stated that, *"Previously, ULNBs were considered capable of providing NOx levels on the order of 20 ppm while firing natural gas."* These statements are incorrect. Unproven emerging technologies should not be considered in any rulemaking process for universal retrofits until after they have been proven in the field. For now, the current ULNBs are the only field proven type of staged internal FGR technology that have guaranteed NOx emissions based on refinery fuel gas (RFG) composition, excess oxygen requirements, bridgewall temperature, and combustion air temperature. Actual NOx emissions typically range from 25 to over 50 ppmvd corrected to 3% excess oxygen on a dry basis depending on the safe operating parameters of the heater, variability of RFG composition, excess oxygen levels, bridgewall temperature, tramp air, and combustion air preheat.

Conformance with Safe Heater Design Standards - FERCo states that, *"Retrofit burners must also comply with API Standard 535 and 560."* This refers to API-535 (reference 1), API-560 (reference 3), and API-560 Addendum 1 (reference 4). API-535 specifically apply to both new heaters and retrofitted heaters; however, API-560 Addendum 1 applies to new heater design. Retrofitting ULNBs should also comply with company-specific heater design standards (e.g., reference 6) that are a result of many years of experience installing and operating heaters with ULNB technology. Particularly important with these design standards is the need to avoid flame impingement. The FERCo report fails to adequately address the limitations to retrofitting the current ULNBs in existing process heaters such as flame impingement on process heater tubes, tube hangers, and refractory surfaces. Flame impingement on process tubes is a safety issue. Flame impingement on process tubes will overheat the tubes, may result in a tube rupture, and a firebox explosion. Flame impingement on tube hangers will cause the hanger to overheat, break, and let the process tubes fall. The tubes could fall into the flame creating tube flame impingement with the results as mentioned above. Flame impingement on the refractory surfaces may overheat the refractory, cause the refractory to fall (spall) off the metal shell, and overheat the metal shell creating cracks in the shell. Because operations and maintenance personnel work near the heater to safely operate and maintain the heater, cracks in the metal shell become a huge safety issue and should be avoided. If the metal shell crack is large enough, the structural integrity of the heater may be significantly compromised and the heater may collapse.

Emerging Technologies - ClearSign and John Zink Hamworthy SOLEX technologies are explained in the FERCo report as emerging, not field proven, technologies. Therefore, they are not viable as a universally feasible retrofit. The Norton Engineering Consultants (NEC) report (reference 7) explains these emerging technologies in more detail and concluded that they are not viable for BARCT.

2.3 Review of SCR Information in Sections 3.2, 4, and 5 of FERCo Report

Technical concerns not addressed or that require clarification in the FERCo report with respect to the feasibility (i.e., safety) and performance of SCR technology are provided below.

SCR Performance Over an Entire Operating Cycle - The FERCo report explains the theoretical equations used in the design of an SCR. The report makes assumptions and suggestions in their calculations that may not be accurate over a five-year or longer (6 to 10 years depending on the unit) turnaround cycle of an operating heater. SCR evaluations should be based on field data over the entire duration of operations and on the actual turnaround cycle for a given unit and not just theoretical equations or an assumed turnaround cycle of 5 years.

Actual SCR Performance Due to Actual Operating Conditions - FERCo theoretically determines the required homogeneity of the NH_3 to NOx ratio based on a root means square (RMS) analysis that must be achieved to comply with their assumptions and suggestions. However, in practice, this theoretical homogeneity is not always achieved or maintained, since flue gas flow deviations occur, heater operating conditions change, and unforeseen events occur such as catalyst fouling or poisoning (reference 2) during operations. When considering all factors in SCR catalyst design per API-536 (reference 2), the actual NOx reduction values will materially deviate from theoretical calculated NOx reduction values. All engineering calculations must have tolerances and design margins. A 2 ppmvd NOx concentration limit with a 5 ppmvd maximum ammonia slip is too low and does not allow for adequate design margins or tolerances for the theoretical calculations or deviations in heater or burner operating conditions or maintenance requirements. FERCo's theoretical example shows a NOx reduction of around 97% (inlet NOx = 70 ppm and outlet NOx = 2 ppm). A reliable NOx reduction value in practice is closer to 92% (inlet NOx = 70 ppm and outlet NOx = 5.6 ppm, assuming corrected to 3% excess oxygen). Even the 5.6 ppm may not be reliably sustainable over a given time period depending upon the operation of the heater, unforeseen events such as catalyst fouling or poisoning, and required maintenance activities such as burner tip cleaning or repairing a malfunction ammonia injection system. The example in FERCo's report should be consider idealized and not reliable for retrofitting existing process heaters.

Byproduct Emissions - The FERCo report briefly addresses ammonium bisulfate and ammonium sulfate formations. Again, the report stated theoretical examples of ammonia slip versus ammonium bisulfate and ammonium sulfate formations. The report states that these reactions occur below 500ºF. If the heater system has a combustion air preheater (APH) and an induced draft (ID) fan, the ammonium sulfates and bisulfates will deposit on the APH and the ID fan internal surfaces downstream of the SCR. Particulate matter will also exit the stack as emissions. Depending on the quantity of deposits, the heater may be prematurely shutdown to clean the APH and ID fan. The loss of revenue for this outage should be considered in the overall economic analysis of installing an SCR. If the system does not have an APH, then the particulate matter will form outside the stack when the flue gas is cooling to ambient temperatures.

Selective Catalytic Reduction Cost Basis: EPA Model and Industry Sources - This section was not reviewed for this analysis and memorandum. However, we note in Table 4-1 on catalyst volume that it uses 5% excess oxygen assumed on a dry basis instead of the required 3% to satisfy the proposed BARCT. Using the standard 3% excess oxygen, the corresponding NOx values will increase by 12.6%.

Impact of Removing Air Preheaters for SCR - FERCo's report at page 5-1 states, *"For instance, for a couple of devices, air preheaters will be removed to accommodate the SCR reactor."* If the APHs are removed and not re-installed downstream of the SCR, then the following scenario may occur that must be weighed into the technical and economic feasibility of such a retrofit:

1. More fuel will be needed to achieve the same process absorbed duty resulting in more operating costs to be considered in the overall economic analysis.
2. If the permitted heat release (HHV) limit is based on fired duty and if the heater is already operating at the permitted heat release, the heater may need to be re-permitted to a higher heat release or otherwise it will lose productive capacity for which such costs need to be considered.
3. If the heater can be repermitted or if the existing permit allows for the higher heat release when the APH is removed, then more CO_2, a greenhouse gas, will be emitted to the atmosphere than a corresponding reduction in NOx emissions.
4. A new ID fan, its ancillary equipment, and foundations will have to be purchased and installed.

5. New foundations will have to be done to accommodate any extra weigh by the SCR installation.

Dual SCR Reactors in Series - FERCo recommends dual SCR reactors in series for BARCT, stating on page 5-3, *"The implementation of SCR NOx control on refinery heater systems can be challenging for many reasons. First and foremost, the physical spaces around these heater units are typically very congested."* If the spaces are very constrained to prohibit the retrofit of an SCR, then an SCR cannot be installed and the NOx emissions will not reliably meet a very low 2 ppmvd standard. Therefore, establishing a very low limit for retrofitting existing process heater would be not feasible or achievable in this situation. The FERCo report ignores this logical eventuality.

2.4 Conclusions

After a thorough review and comments on FERCo's report (reference 5), it is important to recognize the following key conclusions that FERCo should have made regarding technical and economic feasibility of BARCT:

1. Not all existing process heaters can be safely retrofitted with ultra-low NOx burners (ULNBs) to avoid flame impingement on the existing heater process tubes or refractory surfaces.
2. Not all existing process heaters can be retrofitted with SCRs due to space limitations and/or excessively high costs.
3. All existing process heaters must be individually evaluated to determine if ULNBs and SCRs with its ancillary equipment can safely, physically, and economically be installed.
4. A NOx limit of 2 ppmvd (assumed to be corrected to 3% excess oxygen) is not technically achievable for all existing process heaters.
5. A corresponding maximum ammonia slip limit of 5 ppmvd is too low and is inappropriate for being able to optimize NOx reductions for all of the types of existing process heaters .

A universal "one size fits all" approach is not technically, reliably, or practically achievable for establishing NOx removal efficiencies of emission limits for retrofitting existing, older process heaters within refineries.

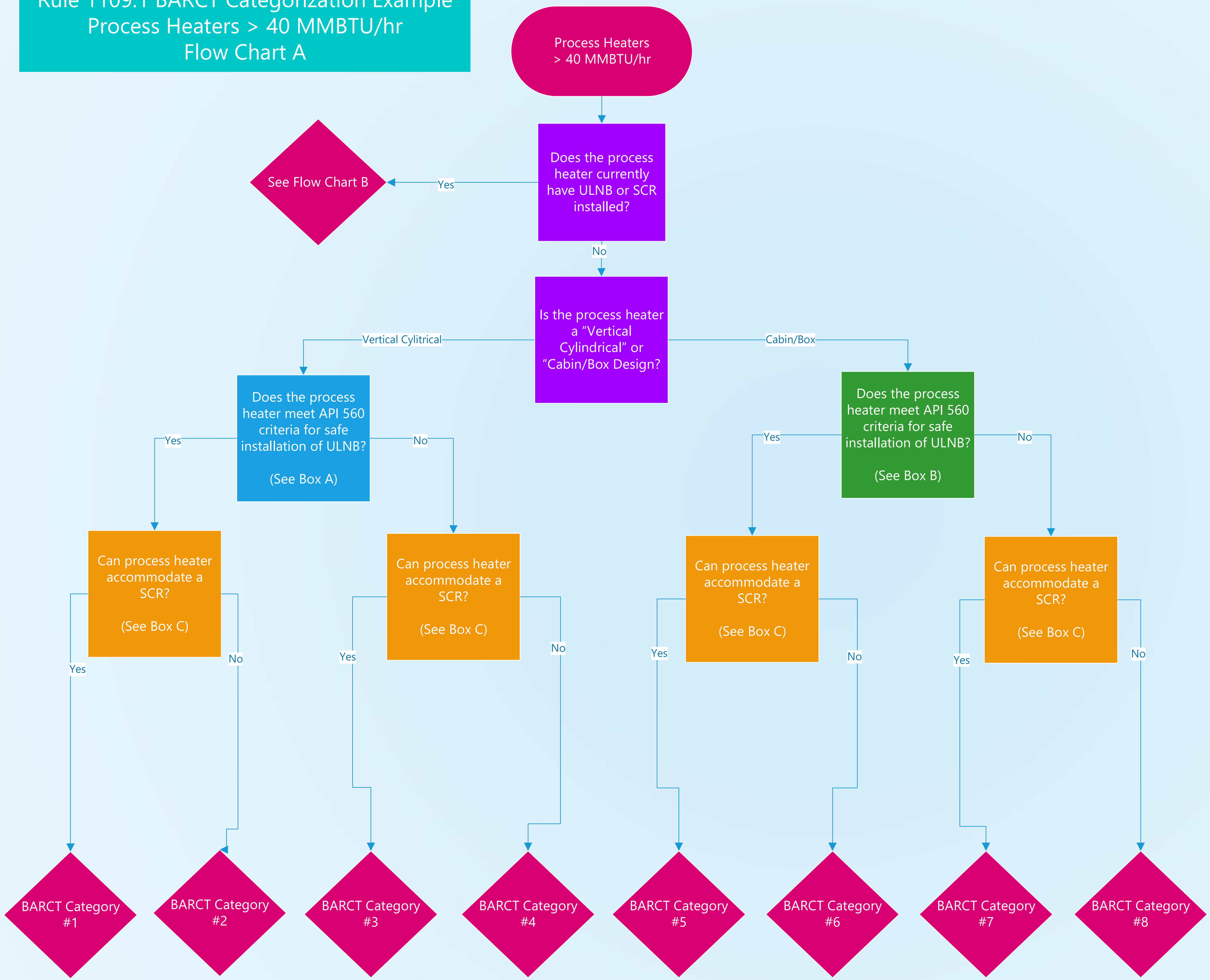
3.0 References

1. American Petroleum Institute (API), API-535, Burners for Fired Heaters in General Refinery Services, Third Edition, May 20, 2014, API Publishing Services, 1220 L Street, NW, Washington, DC.
2. American Petroleum Institute (API), API-536, Post-Combustion NO_x Control for Fired Equipment in General Refinery Services and Petrochemical Services, Third Edition, API Publishing Services, 1220 L Street, NW, Washington, DC.
3. American Petroleum Institute (API), API-560, Fired Heaters for General Refinery Service, Fifth Edition, February 2016, API Publishing Services, 1220 L Street, NW, Washington, DC.
4. American Petroleum Institute (API), API-560, Fired Heaters for General Refinery Service, Fifth Edition Addendum 1 (balloted and approved), publication date pending, API Publishing Services, 1220 L Street, NW, Washington, DC.
5. Fossil Energy Research Corporation (FERCo), South Coast Air Quality Management District Rule 1109.1 Study Final Report, November 2020, Fossil Energy Research Corp, Laguna Hills, CA.

6. Marathon Petroleum Company, SP-45-01, Fired Heater Design, Effective Date: March 20, 2016.
7. Norton Engineering Consultants (NEC), NOx BARCT Analysis Review, Document Number, 19-9009-018, December 4, 2020.

ATTACHMENT D

Rule 1109.1 BARCT Categorization Example
Process Heaters > 40 MMBTU/hr
Flow Chart A



Box A
Vertical Cylindrical Design

- Vertical cylindrical heaters shall be designed with a maximum height-to-diameter ratio of 3.00, where the height is that of the radiant section (inside refractory face) and the diameter is that of the tube circle, both measured in the same units.
- The minimum clearance from grade to burner plenum or register shall be 2 m (6.5 ft) for floor-fired heaters.
- The floor heat flux density for floor-mounted burners cannot exceed 300,000 Btu/hr/ft^2.
- Burner arrangement must meet normalized burner-to-burner and burner-to-coil spacings in equations (5) through (10) of API 560. For vertical cylindrical heaters, the ratio of the burner-circle-diameter (BCD) to the tube-circle-diameter (TCD) shall be designed to satisfy equations (11) through (13) of API 560.
- The burner flame length design shall not exceed 60% of the radiant section height.
- The minimum clearance between the flame envelope, as defined in API RP 535, Section 3.22, and unshielded refractory walls shall be 0.50 ft unless it can be shown that refractory service temperature and velocity limits are not exceeded.

Box B
Cabin/Box Design

- For single-fired, box-type, floor-fired heaters with sidewall tubes only, an equivalent height-to-width factor shall be determined by dividing the height of the wall bank (or the straight tube length for vertical tubes) by the distance between wall tube banks and applying the limitations specified in Table 1 of API 560.
- In cabin and box style heaters, the distance between the unshielded end wall refractory and the nearest burner centerline shall be between 45% and 60% of the burner-to-burner spacing.
- The minimum clearance from grade to burner plenum or register shall be 2 m (6.5 ft) for floor-fired heaters.
- The floor heat flux density for floor-mounted burners cannot exceed 300,000 Btu/hr/ft^2.
- Burner arrangement must meet normalized burner-to-burner and burner-to-coil spacing in equations (5) through (10) of API 560.
- The burner flame length design shall not exceed 60% of the radiant section height.
- The minimum clearance between the flame envelope, as defined in API RP 535, Section 3.22, and unshielded refractory walls shall be 0.50 ft unless it can be shown that refractory service temperature and velocity limits are not exceeded.

Box C
SCR Design

- Plot Space:
  - Is there sufficient plot space around the heater to accommodate a SCR design need to meet the emission limits (e.g., dual catalyst beds, multiple injection grids)
  - Is there sufficient plot space to accommodate a catalyst bed size to meet a superficial velocity (measured as flue gas volumetric rate divided by the front-face area of the catalyst) of less than 10 ft/ second?