Results of the Field Operation of a Distributed-Flux Burner in a Heater Treater in a Northern Canada Heavy Oil Field: Thermal Performance and Firetube Life

D. Bartz and **J. Gotterba,** ALZETA Corporation

Summary

Horizontal heater treaters are commonly used to separate oil/water emulsions from enhanced oil recovery in heavy oil reservoirs. Conventional burners used in these heaters can cause hot spots that result in coking of the viscous emulsion on the outer surface of the firetube. This coking layer acts as an insulator and results in high tube-wall temperatures, leading to an early failure of the firetube. The problem may be exacerbated when polymer injection is used in the recovery fluid because of the increased viscosity of the fluid and the thermal breakdown of the polymer, which create a thicker insulating layer along the firetube.

To reduce coking and the resulting firetube failures, a conventional burner can be replaced with a radiant distributed-flux burner that spreads the heat over a much larger area, with a very uniform flame shape. The distributed-flux burner consists of a porous-ceramic cylindrical surface that provides surface-stabilized premixed combustion, such that combustion characteristics at every point along the cylindrical burner surface are nearly identical. This reduces the peak heat flux within the combustion zone significantly, reducing the likelihood of hot spots and the potential for coking compared with conventional burners. At the same time, more heat is distributed farther down the length of the firetube, increasing heat transfer in the rear section of the heater and improving its overall efficiency and heater throughput. Firetube life is increased because of the lower peak temperatures of the tube wall, and because less heat may be needed to achieve the required process throughput and water cut.

This paper presents data from both pilot tests and field tests of a recent burner retrofit of a horizontal heater treater at an oil sands field in northern Canada. The retrofit was completed in a 2-day effort. On the basis of recent field data, thermal analysis, and measurements made in laboratory tests, the distributed-flux burner is compared with a conventional burner with respect to thermal efficiency and tube-wall temperatures.

Introduction

The use of heater treaters is a common method for heating oil and oil/water emulsions for oil/water separation. However, new challenges in the oil industry are causing problems with this separation method. Wellhead sites with heavy oil can suffer firetube failures in the heater treater; in some cases, this can occur within a few weeks or months of operation. The cause of these failures is fouling from thick oil and polymer additives depositing on the outer surface of the firetube. These deposits insulate and increase the temperature of the firetube until the tube wall ruptures. Failure and replacement of the firetube causes significant downtime and loss of production. This paper describes an effective burner-retrofit solution for the heater treater. The retrofit burner is the distributed-flux burner, which is designed to spread the heat transferred to the firetube over a larger area compared with a conventional burner. The distributed-flux burner uses a unique ceramic-composite matrix that generates uniformly distributed infrared radiation and low emissions of nitrogen oxide and carbon monoxide. In addition to uniform internal heat transfer, variations in external heat transfer must be considered. Experience from laboratory measurements and from field operation of the distributed-flux burners is provided, with strategies to optimize performance of the heater treater.

Heater-Treater Uses and Problems

Heavy oil makes up at least 50% of the world's known oil reserves (Chevron 2010). However, production from these reserves is limited, and only recently have techniques for cost-effective extraction of these reserves become available. These techniques include surface mining, water- and steamflooding, gas injection, steam-assisted gravity drainage with horizontal drilling, polymer injection, and, to some extent, fracturing. For some companies, recovery rates of up to 75% are being achieved (Chevron 2010). Currently, the most-active areas in the world for heavy oil extraction include Venezuela, the Central Valley of California (Bakersfield region), and central Alberta. In Alberta, the heavy oil is in the form of "tar sands" or bituminous sands—a very-high-viscosity mixture of sand, clay, water, and petroleum. Natural bitumen reserves have been estimated at 250 billion bbl worldwide, with approximately 71% in Alberta. Other significant tar sands reserves are found in Kazakhstan and Russia (Meyer and Attanasi 2010). Unlike Venezuela and California, which rely more on thermal-recovery techniques, Alberta primarily uses flooding techniques to drive the oil toward the extraction well. Waterflooding and cold heavy oil production with sand (CHOPS) have been especially effective, and production from heavy oil sites is growing rapidly (Dusseault 2002). In some areas, a polymer is added to waterfloods to improve the mobility ratio and sweep efficiency (Lie et al. 2013). Polymers can modify the physical properties of the injection water to change the way in which the oil and water interact. Polymers can increase the viscosity of water, thus reducing the mobility ratio to improve sweep efficiency. They also have the effect of reducing water consumption, which reduces the operating costs of the well (Kumarswamy 2011).

Most of these enhanced-oil-recovery techniques result in additional water, sand, and other solids in the emulsion. As more techniques for recovering heavy oil and tar sands are applied, there is a greater need to process the oil near the well so that it can be transported efficiently to a refinery; there is no benefit in transporting water and sand to the refinery. Heater treaters are used typically

This paper (SPE 170172) was accepted for presentation at the SPE Heavy Oil Conference—Canada, Calgary, 10–12 June 2014, and revised for publication. Original manuscript received for review 4 November 2014. Revised manuscript received for review 26 February 2015. Paper peer approved 2 March 2015.

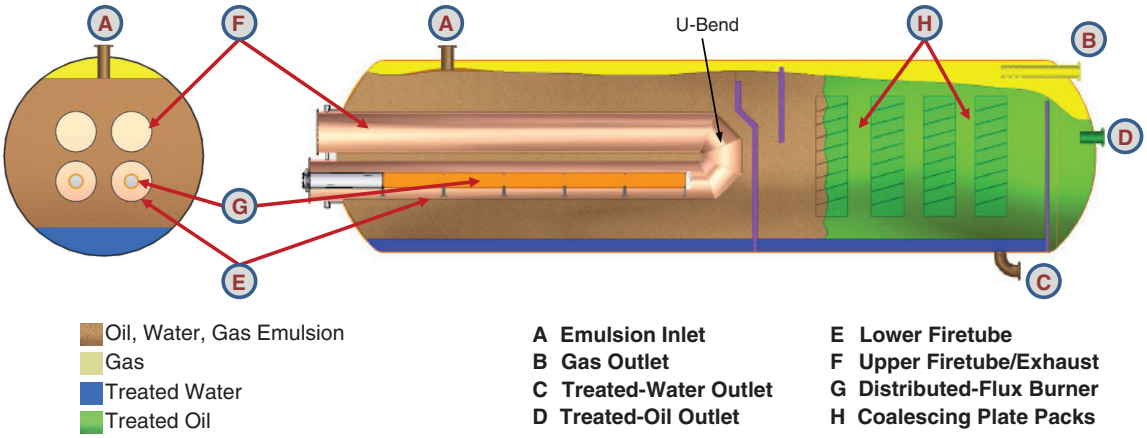


Fig. 1—Typical horizontal heater treater.

to separate water from oil. These units lower the density of both the oil and water and increase the difference in viscosity between oil and water, greatly accelerating separation. The typical heater treater design includes one or more U-shaped heater firetubes inside a tank. Oil/water emulsion enters the tank at one end and flows around the firetube, increasing the emulsion temperature. Gas, water, and oil begin to separate, with the gas rising to the top and the water sinking to the bottom. The emulsion continues to flow through the length of the tank and passes from the heating zone to the separation zone, where a series of baffles, weirs, and sometimes electrostatic separators complete the separation. A diagram of a typical heater treater is shown in **Fig. 1.**

With both waterflooding and CHOPS, the amount of water and sand contained in the emulsion is significantly greater than that from conventional wells. This creates several problems within the heater treater—corrosion, nonuniform flow rates, changing water and sand content—all of which make heater operation more challenging. Along the firetube, these problems can result in fouling and overheating of the tube (Ebert and Panchal 1995). The process of firetube failure can start with sand and/or other solids settling on the surface of the firetube at a time of high heat demand. These solids, contained in heavy oil and bitumen, eventually form an insulating layer of coke on the outside of the firetube, and with less heat being transferred to the emulsion, the result is a high, localized tube temperature. The problem is made worse when polymer is present, in that it can break down and combine with oily solids on the outer surface if the wall temperature becomes too high (Terry 2003). Eventually, the tube wall will lose strength because of the high temperature and will rupture under the operating pressure of the heater treater vessel and localized thermal stresses of the steel wall. **Fig. 2** shows a ruptured firetube wall in a heater treater.

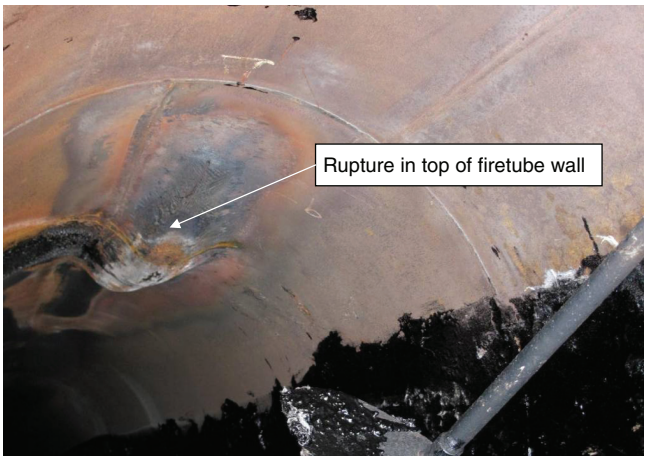


Fig. 2—Photograph of ruptured firetube wall.

At some sites, firetube failure and replacement is standard operating practice. Spare firetubes are kept on-site, and equipment is available for rapid change out. In addition to the cost of having tubes and equipment on-site, a firetube failure represents a costly loss of production. Some mitigating measures can be used, such as reducing the firing rate and lowering the tube temperature, but these all result in reduced productivity and less separation of the oil from the water. In some cases, the heater treater can be the limiting step in production.

Part of the problem is the design of the firetube and the conventional burner system. The firetube, which may be 30 in. in diameter and 25 ft long before the U-bend, is fired at the front end by a single burner. The conventional burner has a flame length limited to a few feet, inherently creating hot zones near the flame. A local hot spot, together with buildup of insulating exterior layers from sands, bitumen, and/or polymer, can cause a tube to overheat—sometimes within hours.

Similar problems exist in other applications. Processes such as asphalt heating, amine reboilers, and other oil or "fragile-fluid" heaters that use immersion-type firetubes also have a potential for fluid coking if exposed to excessively high tube-surface temperatures. Once coking has begun, it will tend to progress over time until the tube fails.

Firetube Failure Resulting From High Firetube-Wall Temperature

When a firetube fails because of high wall temperatures, the sequence of failure is typically as follows:

1. The wall temperature rises above a critical value for any one of several reasons, as discussed in the following. In heavy oil applications, a typical value of this critical temperature, designated as T_{clean}, is approximately 750°F. Above the critical temperature, formation of a coking layer can begin. The literature (Ebert and Panchal 1995) provides studies performed to determine critical values of wall temperature and wall heat flux, where heater exchanger fouling or coking at conditions greater than the critical value.
2. The oil/water emulsion forms a coking layer on the outer surface of the tube, where the wall temperature is high.
3. The coking layer increases the thermal resistance on the outside of the firetube wall. This acts to increase the temperature of the firetube wall and accelerates the deposition of more fouling material.
4. As the firetube-wall temperature increases, the material strength of the steel tube is reduced until plastic deformation occurs in the tube wall, forming a flat spot or concave depres-

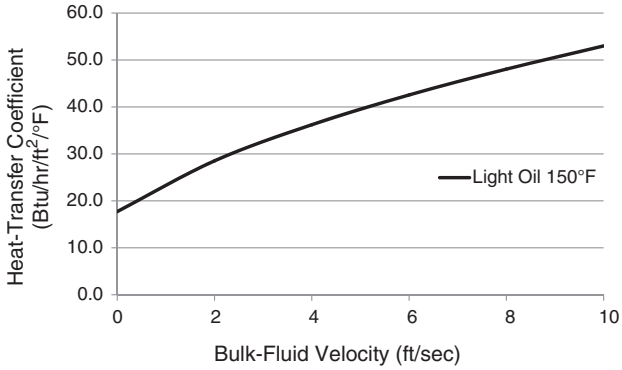


Fig. 3—Heat-transfer coefficient for light oil.

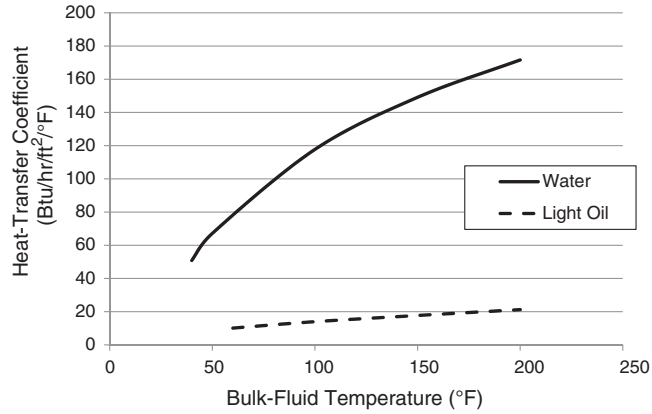


Fig. 4—Effect of fluid temperature on natural-convection heat transfer.

sion at the point of highest temperature. For a 30-in.-diameter a 0.5-in.-thick steel firetube, the wall temperature at which deformation can begin is as low as 850°F.

5. Finally, the tube strength is reduced enough that the tube wall ruptures, enabling pressurized oil emulsion to flow into the interior of the firetube and cause shutdown of the burner.

The temperature of the firetube wall may exceed T_{clean} for a variety of reasons. These are discussed in the following paragraphs, with strategies to prevent the high-temperature excursions.

One cause of high firetube-wall temperature is related to limitations on the external heat transfer from the outer surface of the firetube wall. Typically, velocity of the oil emulsion around the firetube is low enough that the main mode of heat transfer is natural convection. Kreith (1973) provides data and correlations for heat transfer for a 30-in.-diameter heated tube in a horizontal orientation in a light oil bath. The estimated average heat-transfer coefficient is 18 Btu/hr/ft^2/°F. This value is less for the top, or 12-o'clock, position of the tube, and is reduced for heavy oil. For these conditions, the local heat-transfer coefficient is estimated to be 12 Btu/hr/ft^2/°F. For a typical process temperature of 250°F and a critical temperature of 750°F, this results in a maximum limit on heat flux from the tube (designated as u_{clean}) of 6,000 Btu/hr/ft^2. If the local heat flux exceeds 6,000 Btu/hr/ft^2 for this example, the wall temperature will rise above 750°F, leading to coking on the exterior of the tube. One strategy to prevent reaching the critical wall temperature is to limit the internal heat flux to the inside surface of the firetube wall to 6,000 Btu/hr/ft^2.

The value of the external heat-transfer coefficient for the firetube wall may not be uniform over the exterior surface of the firetube. There may be reduced values of the coefficient because of

- Low-flow zones, in which natural convection is impeded by the structure of the firetube. This is true, for example, near the inner surface of the U-bend seen in Fig. 1. Convective flow of the emulsion is reduced in this area and can cause early onset of the coking layer and firetube failure. This occurred in one of the field installations discussed later. Heat flux may need to be reduced in this area to prevent formation of the coking layer.
- Formation of solid layers on the tube wall. Sand, for example, can deposit on top of the outside surface of the firetube wall, resulting in an insulating layer that raises the tube-wall temperature. Some heater treaters incorporate jets of pressurized water or desand systems to dislodge the sand that deposits on the tube. This discussion of high firetube-wall temperature includes formation of the solid coking layer.

In some locations in the heater treater, natural convection may be augmented by forced convection as a result of higher fluid flow at the entrance of the heater treater. Where this occurs, the external heat-transfer coefficient may be considerably higher than the value for natural convection. This effect is shown in **Fig. 3** for light oil, from published data (Kreith 1973).

Another cause of high firetube-wall temperature is related to the accuracy of the control scheme to maintain the temperature of the process flow or oil/water emulsion. In a typical heater treater, the burner firing rate is determined by a closed-loop temperature controller. The controller receives the process-temperature measurement, compares it with the set point, and adjusts the burner firing rate by use of a proportional-integral-derivative-feedback algorithm. When operating conditions are steady, this control scheme works well. With large or rapid changes in process conditions, particularly process-flow rate, accuracy of the temperature control loop may suffer. With a sudden increase in oil-/water-flow rate, for example, the process temperature will drop, resulting in a large temperature error and a large increase in burner firing rate to catch up. Care should be taken to limit the peak firing rate to prevent high tube-wall temperature. Also problematic is a sudden decrease in process flow. This will increase the process temperature, reduce the external heat-transfer coefficient, and increase the lag or delay between change in burner firing rate and process-temperature change. All these effects can contribute to a high firetube-wall temperature.

Yet another condition that can lead to high firetube-wall temperature may occur during cold startup. Typically, viscous heavy oil will have a much-lower external heat-transfer coefficient while cold. **Fig. 4** shows the effect of fluid temperature on the heat-transfer coefficient for light oil and for water along a flat plate (Kreith 1973). Until the process temperature reaches a warm-up value of approximately 150°F, the firing rate of the burner must be limited to approximately one-half of the maximum firing rate. Once the fluid in the heater treater is above the warm-up value, the burner firing rate may be increased. This can be achieved with a "low-fire-hold" to fix the firing rate at a low value until it is released to modulate by a temperature switch set to the warm-up value.

Finally, the firetube-wall temperature may reach high values because of nonuniform internal heat transfer. This is true for short, intense burner flames that have high values of localized heat flux. The key strategy here is to distribute the heat flux over as much of the firetube area as possible. This is the design basis for the distributed-flux burner described in the following. Excess air can also be used to reduce the peak heat flux of the burner, but it also reduces thermal efficiency of the heater somewhat, requiring more fuel for the same heater duty.

From this discussion, we can consider a few figures of merit for the performance of the heater treater burner:

- Heater treater thermal efficiency (η_{th}): This common performance standard is equal to the heat transferred to the oil/water process fluid divided by the total heat input or burner firing rate. To minimize fuel costs, the heater thermal efficiency should be maximized. Typical values for a heater treater are

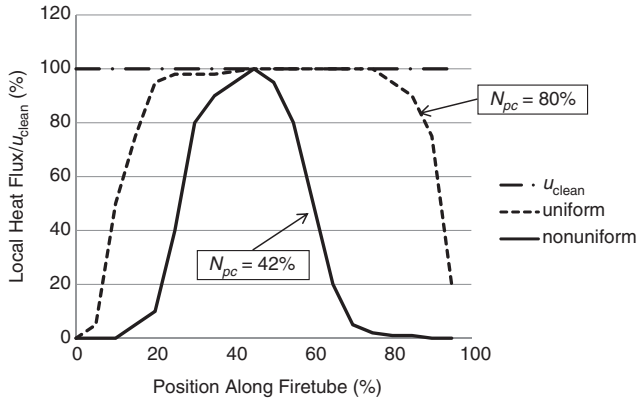


Fig. 5—Example heat-flux profiles.

70 to 80% with powered burners, but can be much less with atmospheric burners.

- Production-capacity ratio (N_{pc}): This quantity, derived for this article, is a measure of the uniformity of the heat-transfer rate to the firetube. It is equal to the heat transferred to the oil/water process divided by the product of firetube surface area and maximum heat flux without fouling, u_{clean}. Notice that the production-capacity ratio is equal to 100% if the firetube wall sees the peak heat flux over its entire length. **Fig. 5** shows an example of a uniform and nonuniform burner profile of internal heat transfer. In both cases, the peak value of heat flux u_{max} is limited to u_{clean} to avoid fouling. When values of N_{pc} approach 100%, the maximum amount of heat is being transferred to the process fluid without formation of a coking layer. Consequently, the amount of heat absorbed for a uniform burner profile is much more than that for the nonuniform burner profile, and separation of the oil/water emulsion is maximized for a specific heater treater.
- Mean time between failure for firetubes: This is another common performance standard. By properly addressing the causes of firetube thermal failures discussed in the preceding, the goal is to maximize operation time for the firetube. This reduces the costs of firetube replacement and lost production from the heater being out of service.

Characteristics of the Distributed-Flux Burner

The distributed-flux burner is able to extend the flame zone down the length of the firetube and provide a lower, more-uniform heat flux to the firetube over a much larger area. This effectively reduces the firetube-wall temperature and avoids hot spots and formation of insulating layers of coke. Conventional burners typically have nozzles or mixing devices that propel the air and fuel into a firetube where they are combusted. The shape, size, and quantity of the nozzles all affect the flame shape and quality of combustion. Typical flame geometry will have a flame length that is 1.5 to 2.5 times the width. If the flame extends farther, it can become unstable and partially extinguish.

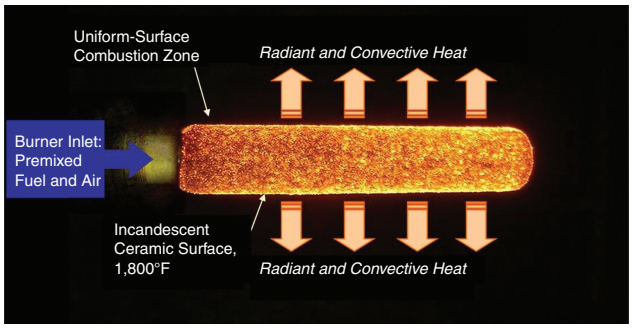


Fig. 6—Distributed-flux burner in operation.

The distributed-flux burner, however, relies on surface-stabilized combustion. The fuel and air are premixed and flow through a porous refractory tube, and burn on the outer surface of the tube. Combustion is the same at every point, producing a uniform, stable reaction with significant surface radiation and essentially no visible flame. An illustration of the burner is shown in **Fig. 6,** showing how infrared radiation is transmitted from the burner surface to the load. The burner can be built in many geometries, but for heater treaters, the burner shape is cylindrical with very large length/diameter ratios, typically 15:1 to 25:1, allowing distribution of the flame over a long length. The burner is located along the centerline of the firetube and extends along most of the firetube's first pass. **Fig. 7** shows the distributed-flux burner inside the firetube. The heat release of the burner is thereby distributed over much longer length, limiting the peak rate of heat transfer to the tube. Because of the uniformity of the surface-stabilized flame, the combustion products contain low levels of nitrogen oxides and carbon monoxide (typically less than 10 ppm). Unique features of the burner are

- Uniform heat distribution over a large area to minimize peak heat-transfer rates
- Low emissions
- Quiet operation; essentially no combustion noise
- Reliable long-term operation with easy maintenance
- Simple to start up
- Easy to retrofit in standard firetube heaters

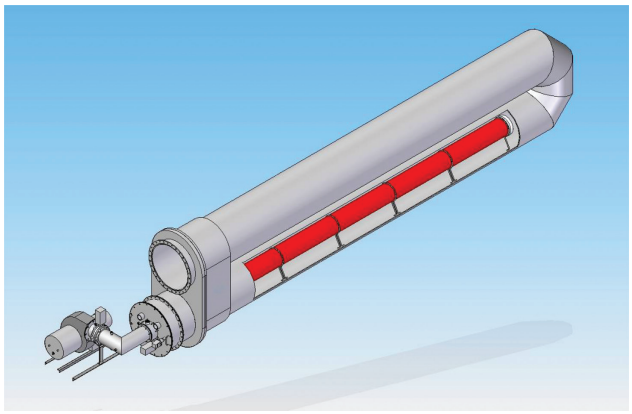


Fig. 7—Arrangement of distributed-flux burner (red) in the firetube.

Thermal Analysis

One way to evaluate the uniformity or distribution of heat transfer inside the firetube is by thermal analysis. The interior of the firetube is divided into finite elements. Conservation of mass and energy is provided at each element to determine the local heat flux to the firetube wall. Each element includes convective heat transfer and gas-phase radiation. Burner-to-surface radiation is also included in those elements where the burner is located.

Fig. 8 shows results for the distributed-flux burner and a conventional burner over the entire length of a firetube (both the combustion leg and the return leg). Note that the peak heat flux for the conventional burner is much higher compared with the distributed-flux burner. In **Fig. 9,** the firing rate for the conventional burner has been reduced to keep the peak flux the same as that for the distributed-flux burner. For this case, the production-capacity ratio (N_{pc}) for the distributed-flux burner is approximately double the value for the conventional burner. This indicates that the expected process throughput is also approximately double for the distributed-

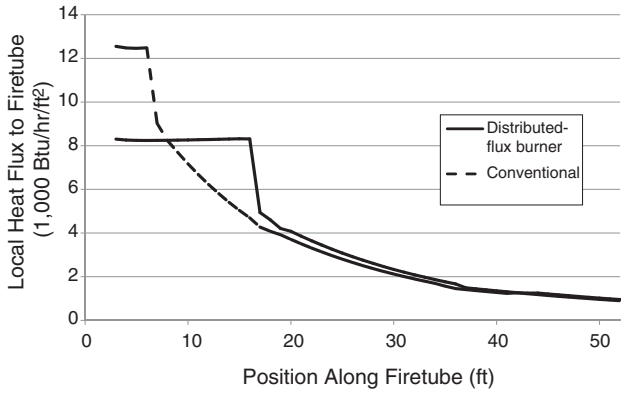


Fig. 8—Analysis of the heat-flux profile—distributed flux and conventional burner.

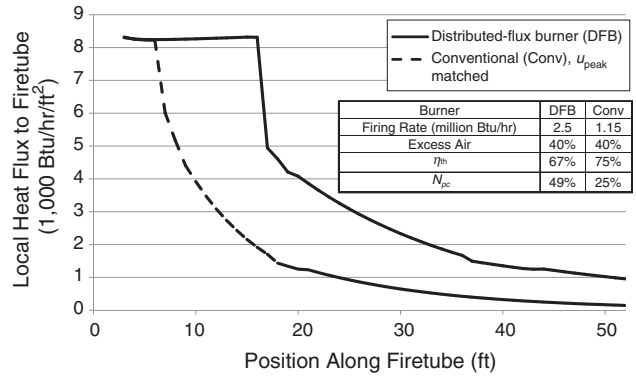


Fig. 9—Analysis of the heat-flux profile with equivalent peak flux.

flux burner compared with the conventional burner, even though the peak heat flux and firetube-wall temperature are the same.

In **Fig. 10,** effects of burner length and excess air are evaluated for the distributed-flux burner. All cases have adjusted the firing rate to limit the peak flux to the same value of 8,300 Btu/hr/ft^2. For the case with burner length of 8 ft compared with 16 ft, the firing rate must be reduced considerably, with resulting N_{pc} of the 8-ft burner being similar to that of the conventional burner. Comparing excess air values of 20 and 40%, the greater excess-air value results in lower thermal efficiency, but greater N_{pc}. Effectively, more heat has been diverted to the second pass of the firetube heat exchanger. Fig. 10 shows the benefit of operating at high excess air and with long burner length.

Field Experience With the Distributed-Flux Burners

The first distributed-flux burners were installed in asphalt heaters in Edmonton, Alberta, in 1986. Similar to heavy oil heating, asphalt-storage-tank heaters require uniform heat transfer to prevent coking and buildup of material on the firetube wall. As a result of the retrofit burners, heat input to the storage tanks was increased without damage to the firetubes, allowing the asphalt delivery trucks to increase their delivery range by one-third. Uniform heating of the asphalt allowed an increase in process temperature without firetube fouling. Noise from the original burners was reduced from 110 to 80 dba (Kesselring 1986).

In November 2013, two distributed-flux burners were installed in a heater treater that processes heavy oil in Northern Canada. **Fig. 11** shows a burner inside one of the firetubes. After new controls and gas trains were located nearby, the switchover and startup to the distributed-flux burners was completed in less than 2 days. The distributed-flux burners replaced atmospheric burners, providing an increase in thermal efficiency and allowing for higher process throughput with improved water separation, or water cut, compared with the original burners. In this installation, however, we still encountered several of the wall-temperature issues described in the preceding. Because the original atmospheric burners ran at very high values of excess air and low thermal efficiency, the new distributed-flux burners, operating at higher thermal efficiency, were oversized by almost a factor of two. As a result, initial warm up of the heater treater from cold conditions was too rapid and may have led to early formation of a coking layer. Second, the maximum firing rate of the distributed-flux burner was too high and resulted in an additional coking-layer formation. Finally, we determined that despite a uniform distribution of internal heat transfer, the firetube-wall temperature was not uniform because of variations in the external heat-transfer rate. In this heater, we learned that external heat transfer is high in the front because of the positioning of the inlet flow duct into the heater treater. We also learned that external heat transfer is low in the rear because of flow obstruction near the U-bend. A firetube failed in approximately 8 weeks of operation, with tube deformation forming at the 12-o'clock position near the rear. The next step for this installation is to provide burners with a smaller diameter to enable operation at much lower firing rates. This will prevent excessive heat transfer to the firetube and avoid early formation of the coking layer.

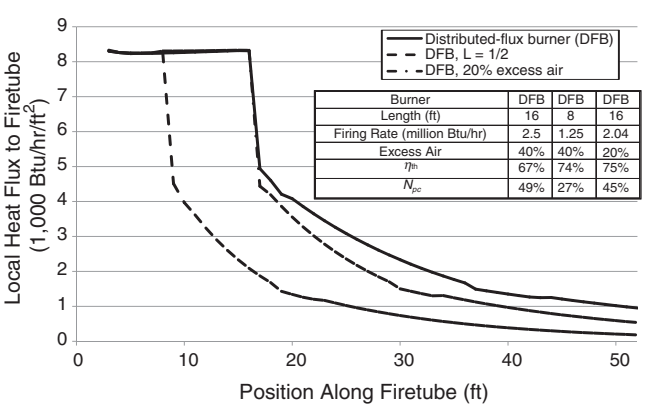


Fig. 10—Analysis of the effect of length and excess air on performance.

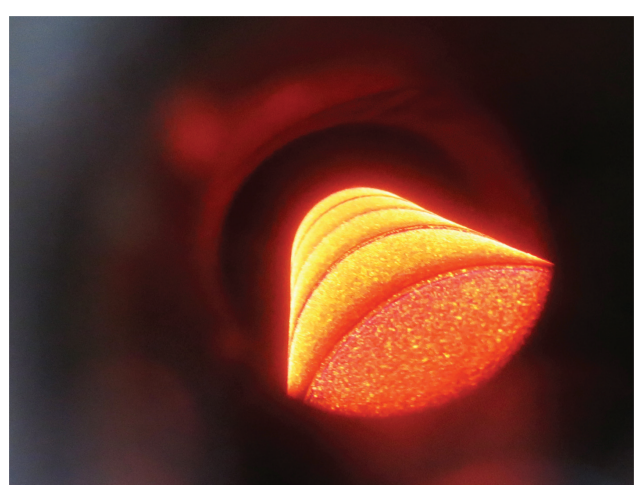


Fig. 11—Distributed-flux burner operating in a Canadian heater treater firetube.

Distributed-flux burner size	4-in. diameter, 45-in. length
Firing rate	200,000 Btu/hr
Excess air	70%, with distributed-flux burner
	130%, with conventional burner
Firetube diameter	10 in.
Firetube material	Polished stainless steel
Process fluid	Atmospheric air at 70°F

Table 1—Parameters of the laboratory-test unit.

Another installation of the distributed-flux burner is in three heater treaters located in California. Each heater has two burners that are each sized for 8 million Btu/hr. This application requires uniform heating as well as low nitrogen oxide emissions. The distributed-flux burners in these heaters have operated successfully since 1995. Recently, one of the heater firetubes failed, with a deformation occurring approximately 60 in. from the inlet flange. This site had undergone changes in the oil/water emulsion supply to the heaters, which resulted in more rapid, large-magnitude changes of flow rate. Additionally, in the firetube, the burner remained in operation when flow to the heater treater dropped to zero. The recent firetube failure is attributed to these process-flow effects, making control of the process temperature difficult and resulting in high tube-wall temperatures. Changes will be made to the process-flow control to enable steadier flow of the process and more-accurate control of the process temperature.

Laboratory Measurements of the Distributed-Flux Burner

To verify analysis and design of the distributed-flux-burner characteristics, we operated a one-third-scale distributed-flux burner and a conventional atmospheric burner in a firetube in our test facilities. Key parameters of the test unit are detailed in **Table 1.**

The goal of the test was to operate the burners in an environment in which the external heat transfer was uniform over the length of the firetube. In this way, we can measure the temperature profile of the firetube wall and thereby determine the local internal heat transfer from the burner to the firetube.

The firetube-wall temperature was measured by use of an infrared (IR) camera and ten thermocouples welded to the firetube as a check on the IR measurement. We measured the firetube exhaust temperature to determine overall heat transfer and thermal efficiency. Heat flux from the tube wall, equal to the internal heat transfer from the burner, is calculated from the wall surface-temperature measurement. The external heat transfer comprises radiation heat transfer and natural convection from the surrounding air, both functions of the wall temperature and ambient air temperature. **Fig. 12** shows IR photographs taken of the laboratory-test firetube. Burner exhaust gas flows from left to right in the photograph. The burners each were mounted to a flange to the left of the photographs, located 70 in. upstream of the start of the 45° bend. Thermocouples are welded to the firetube along the bottom edge. The top photo shows an IR photograph of the firetube with the conventional burner in operation. A hot spot is evident along the bottom edge of the firetube. The IR photograph was calibrated with the thermocouple measurements to determine the outer-wall surface temperature. The lower photo shows the firetube with a distributed-flux burner installed. Notice that the wall-temperature profile is much more uniform in the lower photograph. The warm zone along the top, evident in both IR photographs, is likely caused by low convective heat transfer of the ambient air at the top of the tube, and is not representative of the thermal environment in a heater treater.

By use of the thermocouple measurements of the tube wall, the local heat flux is calculated by evaluating natural-convection and radiation heat transfer from the tube wall. **Fig. 13** shows the result in heat-flux profile for the two burners, normalized to the peak heat flux occurring at the maximum measured wall temperature. As shown in Fig. 13, the profile of the distributed-flux burner is flatter and more uniform compared with that of the conventional burner. The value of N_{pc}, a measure of uniformity, for the distributed-flux burner is 24% greater than that for the conventional burner. In addition, thermal efficiency is greater for the distributed-flux burner. On the basis of these data, the distributed-flux burner provides more-uniform internal heat transfer compared with the conventional burner.

Recommendations

Fouling and formation of coking layers on firetubes can be reduced by preventing high firetube-wall temperatures. From experiences in field operation of heater treaters for heavy oil processing, strategies developed to prevent high firetube-wall temperatures, while maximizing process throughput, include

- If possible, identify the maximum wall temperature T_{clean} that will avoid fouling. Suggested starting values of u_{clean} and T_{clean} are 6,000 Btu/hr/ft^2 and 750°F, respectively.
- Limit the maximum burner firing rate so that the peak heat flux is less than u_{clean}.
- Maintain steady flow of process oil/water emulsion to help achieve accurate temperature control in the heater treater.
- Use low-fire-hold control strategy to limit the initial firing rate until the process has warmed up.
- Prevent high internal-heat transfer in dead zones in the heater (e.g., near the U-bend).
- Select the burner with high uniformity to obtain the most heat transfer while limiting the peak heat flux to be less than u_{clean}. A measure of uniformity of internal heat transfer is production-capacity ratio, N_{pc}.

Conclusions

Enhanced oil recovery by steam- and waterflood is being used increasingly to improve reservoir recovery rates. This results in high water content in the emulsion. To separate the water from the oil, fired heater treaters are commonly used. Heavy oil, along with sand, asphaltenes, and sometimes polymers, can combine to build an insulating layer on the outside of a firetube, where localized tube temperatures peak because of poor heat distribution from a conventional flame burner. At some point, the material strength of the tube decreases until it deforms or ruptures under pressure from the surrounding emulsion. Such premature firetube failures are costly, not just because of the reoccurring high cost of replacing firetubes, but also because of the significant loss of production time.

Distributed-flux burners provide a more-uniform heat that minimizes or eliminates local hot spots and reduces firetube failures. More significantly, these burners also have the potential of increasing production, as indicated by the production-capacity ratio N_{pc}. However, field experience has demonstrated that it is also important to consider parameters such as differences in heater thermal efficiency, burner firing rate relative to heater duty, variations in heater throughput, and flow around the firetube when sizing a burner for a specific application. Hence, distributed-flux burners can now be better designed and sized for the application. Future work should focus on documenting burner life and quantifying improvements in oil production and water cut.

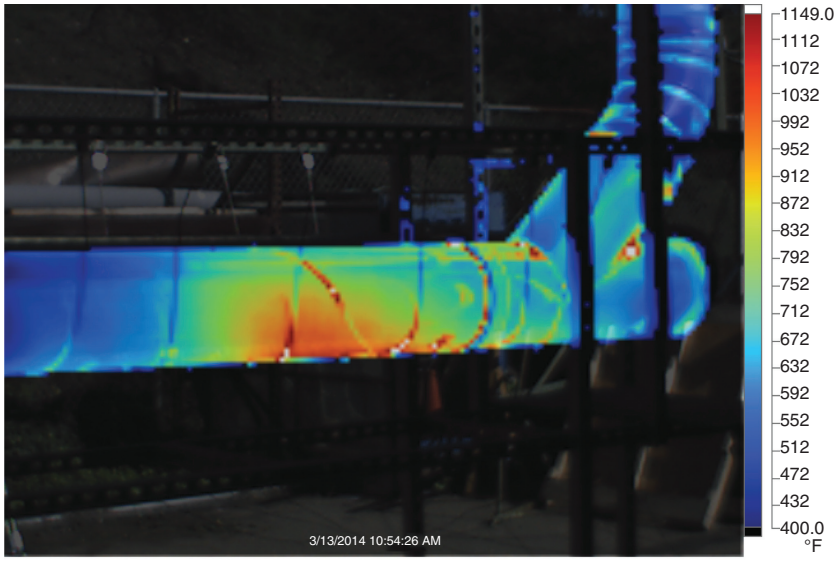
Nomenclature

N_{pc} = production-capacity ratio, a measure of uniformity of internal heat-transfer profile for a burner, dimensionless

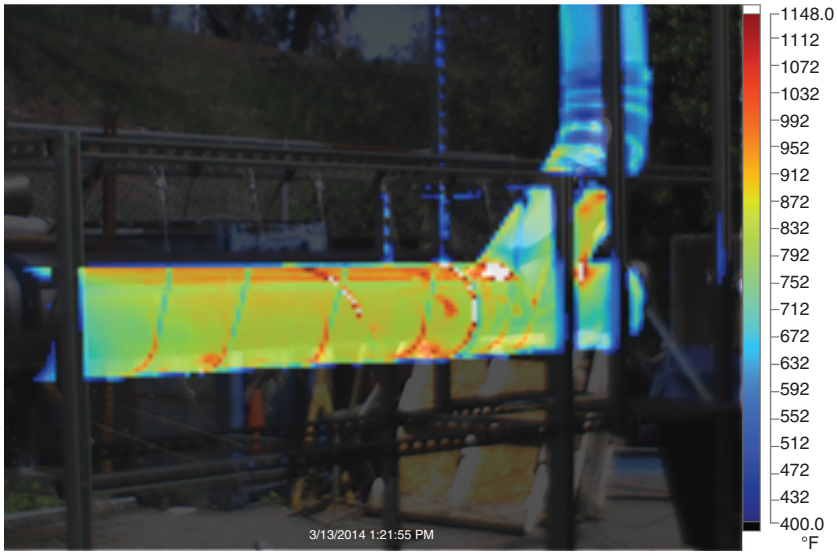
T_{clean} = maximum value of the firetube-wall temperature without forming a coking layer, T, °F

u_{clean} = maximum value of heat flux to a firetube wall without forming a coking layer, m/t^3, Btu/hr/ft^2

u_{max} = maximum value of the internal heat flux to the firetube wall from the burner, m/t^3, Btu/hr/ft^2



(a) IR photograph of laboratory firetube with conventional burner



(b) IR photograph of laboratory firetube with distributed-flux burner

Fig. 12—Laboratory-test-rig IR photographs.

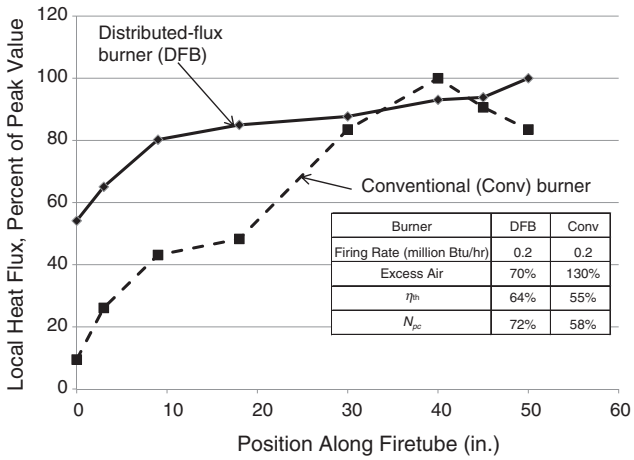


Fig. 13—Local heat flux along the bottom of the firetube—laboratory-test results.

η_{th} = thermal efficiency, ratio of heat absorbed to heat rate supplied to the burner, dimensionless

Acknowledgments

The authors wish to thank Daniel Carey for his valuable assistance in the laboratory testing and data analysis.

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David Bartz is Manager of Product Development at ALZETA Corporation. He has more than 25 years of experience in design and development of industrial- and commercial-burner systems for achieving process improvements and low nitrogen oxide emissions. Bartz has authored articles that have been published in the conference proceedings of SPE, the Air and Waste Management Association, and Pollution Engineering. He is a registered mechanical engineer in California, and holds a BS degree in mechanical engineering from the University of California, Berkeley, and an MS degree in mechanical engineering from Stanford University. Bartz is a member of SPE and the American Society for Mechanical Engineers (ASME).

James Gotterba is Manager of Market Development at ALZETA Corporation. He has more than 30 years of experience in developing and commercializing process equipment and burner systems by use of ALZETA's surface-combustion-burner products. Gotterba holds several US patents for surface-combustion-burner applications, and has presented papers at the conferences of the Air and Waste Management Association, Power Gen, and other venues. He is a registered professional engineer in California, and holds a BS degree in mechanical engineering and an MBA degree. Gotterba is a member of SPE and ASME.