VAPOR PRESSURE MODELING OF COLD WEATHER MODIFICATIONS FOR BAKKEN SURFACE FACILITIES

BACKGROUND

Under the Bakken Production Optimization Program (BPOP), the Energy & Environmental Research Center (EERC) applied experience gained from modeling surface facilities to evaluate factors that influence crude oil vapor pressure, including facility design, operating parameters, and the impact of ambient conditions. Bakken producers typically condition crude oil at the wellsite using one or more stages of pressurized gas–oil separation and with a final near-atmospheric separation in the oil storage tanks. It is the effectiveness of these separations and the residual gas content of the oil that ultimately determine its vapor pressure.

To aid in the safe transport of Bakken crude, producers must comply with oil vapor pressure limits set forth in North Dakota's conditioning rule or lower vapor pressure limits set by crude oil transporters. North Dakota's limit of 13.7 psia can typically be met without special precautions during summer months, but during the winter, ambient conditions hinder effective gas–oil separation that can result in exceeding vapor pressure limits.

MODEL DEVELOPMENT

Facility modeling was accomplished using site-specific information from two BPOP member production locations. Operational data and oil samples from these two sites were collected during winter 2017–2018. A summary of the wellsite configurations are provided in Table 1.

Table 1. Modeled Wellsite Conditions

	Site 1	Site 2
Number of Wells	9	3
Nominal Oil Production	3000 bbl/day	110 bbl/day
3-Phase Separator Conditions		
Pressure	35 psig	60 psig
Set Point Temperature	125°F	120°F
Observed Downstream Temperatures	122°F	70°–90°F
Production Tanks	5	1

Oil throughput was a key distinguishing factor between Sites 1 and 2. In order to accurately model low-flow Site 2, it was important to identify actual temperature trends for its 3-phase, heated separator (treater). Measured temperature data are plotted in Figure 1, illustrating treater outlet oil temperatures as a function of the daily average temperature. For modeling, these outlet temperatures were assumed to be representative of the bulk gas–liquid separation temperature within the treater rather than the treater set point of 120°F.

RESULTS

Oil vapor pressure is determined by both a flash separation in the treater (at pressures ranging from 20 to 100 psig) followed by a near-atmospheric flash in the storage tanks. As indicated by the green line in Figure 2, oil exiting Site 1's treaters was sufficiently conditioned so that its vapor pressure would not exceed 13.7 psia under a range of expected tank temperatures. Site 2, which has a lower production rate, operated with lower overall fluid temperatures and was, therefore, less able to meet the 13.7-psia limit when ambient, and associated tank temperatures were low. The red solid line in Figure 2 indicates that when the fluid temperature at the treater exit was 78°F, the receiving tank temperature would need to be warmer than 53°F in order to achieve the target vapor pressure. Alternately, if the fluid temperature exiting the treater were 120°F, the receiving tank temperature could be as low as 11°F and still achieve the target vapor pressure.

Because of its higher crude oil vapor pressure, Site 2 was modeled further to evaluate the effect of several modifications to the conditioning equipment. The modifications consisted of insulating the transfer piping between the treater and the tank battery, insulating the single production tank, and heating oil in the production tank. Modeled results from these different scenarios are summarized in Figure 3, which compares each modification according to the ambient temperature that would result in a 13.7-psia oil vapor pressure.

Based on the analysis shown in Figure 3, insulation of either the piping or tank alone did not result in much added cold-weather resilience; however, in combination they are effective at achieving the target vapor pressure down to an ambient temperature of −12°F. Similarly, adding a tank heater alone provided little benefit to crude oil vapor pressure, but in combination with an insulated tank, the vapor pressure target could be achieved at an ambient temperature of −26°F. These results illustrate that oil must enter the storage tank with enough flash energy (or have it added using a heater), and the tank heat loss must be minimized.

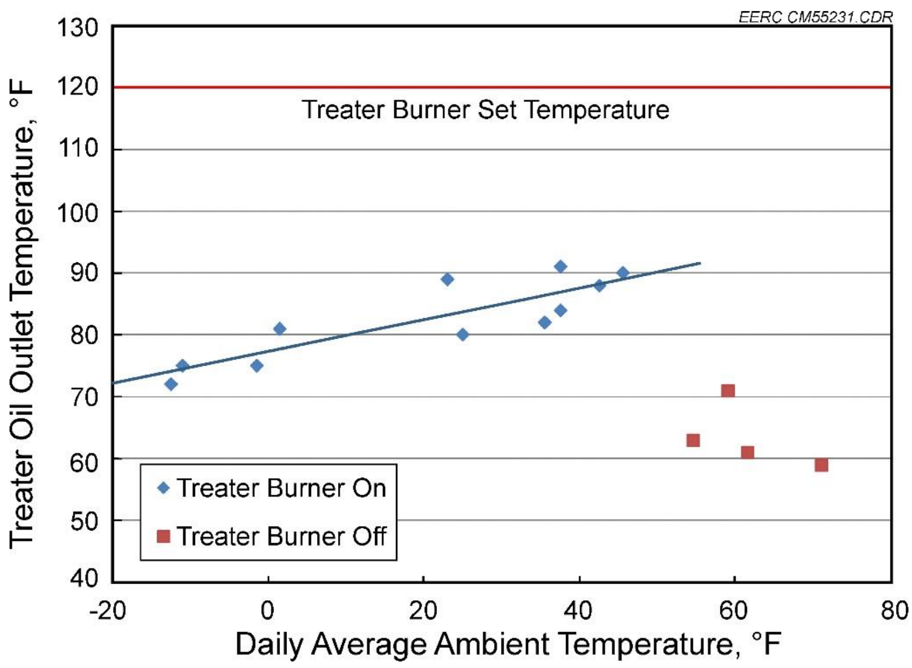

Figure 1. Recorded temperature data for the 3-phase separator at Site 2.

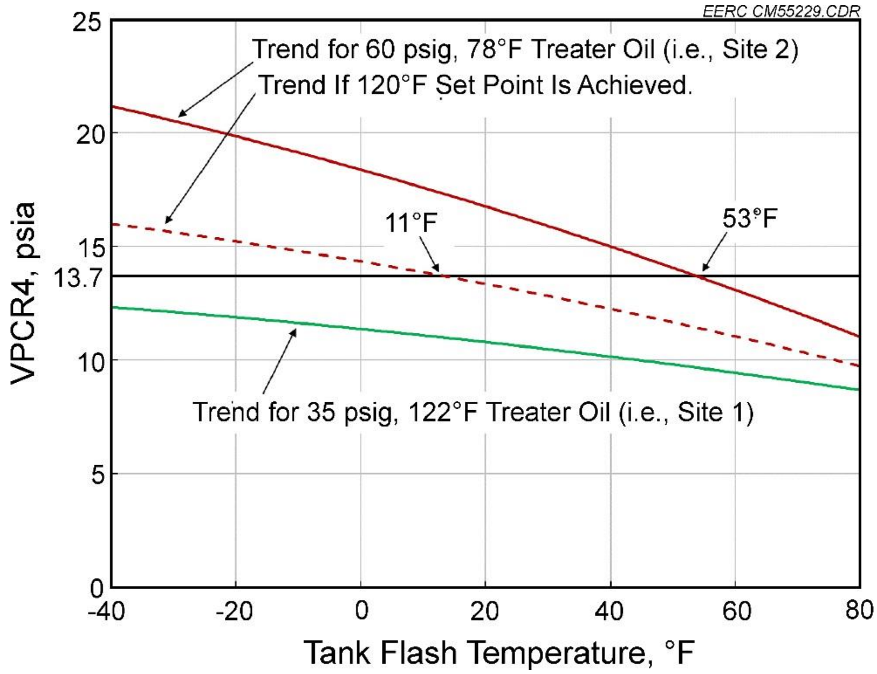

Figure 2. Flash temperature effects on the vapor pressure of oil from each site (VPCR4 is the vapor pressure of crude at a 4:1 expansion ratio).

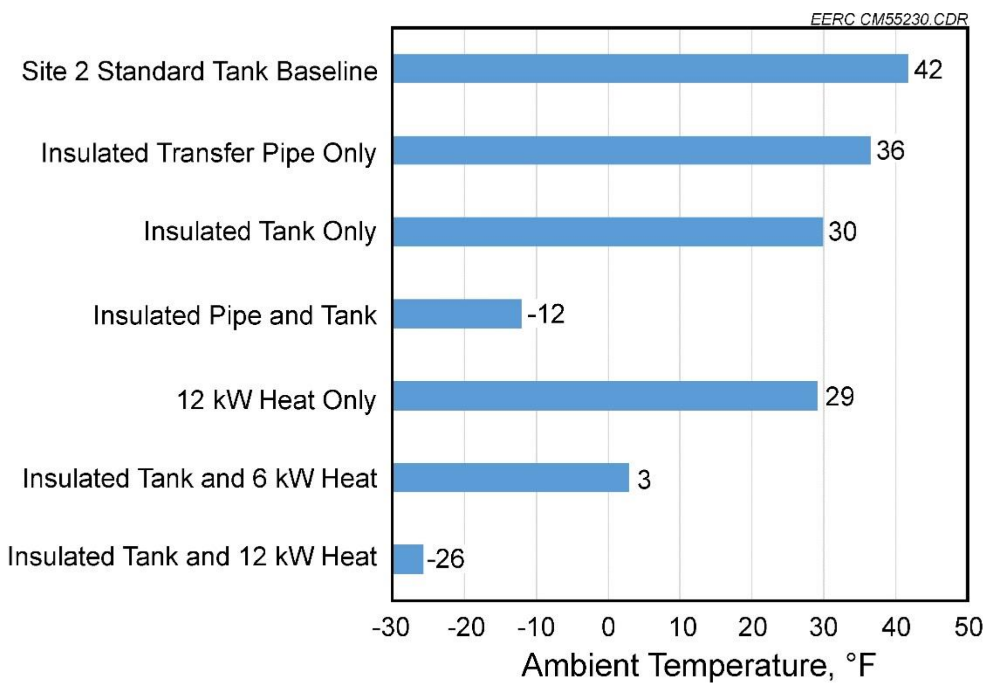

Figure 3. Predicted ambient temperatures resulting in 13.7-psia oil.

RECOMMENDATIONS

The contrast in vapor pressure trends between Site 1 and Site 2 is primarily due to the production rate at each site. High flow associated with Site 1 limited heat loss to the environment and resulted in effective separation of gas from oil in the treaters and storage tanks. On the other hand, low-throughput Site 2 was more sensitive to ambient heat loss and elevated vapor pressure. For low-flow sites like Site 2, modeling highlighted two general approaches for counteracting high oil vapor pressure during cold conditions:

1. Address the poor low-flow performance of treaters to prevent high vapor pressure oil from reaching the tank battery. Options might include the following:

    - Improve mixing and temperature uniformity with the treater, especially under low-flow conditions.

    - Preheat the fluid entering the treater to the desired set point and minimize treater heat loss.

2. Modify the tank battery to maintain an effective atmospheric flash under all expected weather conditions. Recommendations from modeling show the following to be most effective:

    - Produce into a single tank or dedicated flash vessel.
    - Insulate this vessel, and add heating capability for maximum resilience.

Note that pursuing Alternative 2 may increase tank vapor generation; therefore, potential impacts to the tank venting system should be evaluated as part of any design modification.

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