Analysis of MC20 seafloor hydrocarbon plume flow dynamics and thermohaline signatures

Prepared for Taylor Energy

by

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Introduction

This report examines the characteristic indicators that would necessarily be associated with an active well leak from the MC20 site. The analysis contained in this draft document is intended to serve as a complementary tool for use in conjunction with prior analyses conducted as part of the MC20 response operations, with the objective of providing actionable information for the following:

- Positively identifying the well/s associated with any active leaks.
- Estimating the magnitude/s of any such leaks.
- Understanding the minimum limits of detection for any given well leak,
- Characterizing the theoretical maximum flow from each well.

Of the MC20 wells, the natural gas wells (A-11, A-13, A-17, A-23, and A-28) are not considered. For purposes of this analysis, each oil well (A1, A2, A3, A4, A6, A7, A8, A9, A10, A12, A12D, A14, A16D, A18, A19ST, A20, A21, A22, A24, A25, and A26) is assumed to be capable of flowing unimpeded by hydraulic losses, reservoir pressure limitations, or prior plugging operations. Using this flow capability assumption, we now consider the inherent characteristics of each well at any presumed leakage rate. Among the characteristics of interest are:

- volumetric rate of formation water production
- volumetric rate of well gas production
- fluid velocity at conductor exit
- thermal signature at the mudline
- salinity signature at the mudline

Volumetric flow rate of reservoir formation water

Each of the MC20 oil wells has an associated formation water (brine) production rate that scales with increased oil output. The “water cut” percentages are unique to each well, with higher percentages typically associated with wells that are nearing end of life. Wells, including A7, A18, A3, A10, A12D, A8, A4, and A12 produce between 90 and 99% formation water (i.e., for every gallon of oil produced from one of these wells, at least 9 additional gallons of formation water is also produced). The rate of formation water (brine) generation from a leaking well has profound implications to the detectability of a leak and to the upper bound of the flow rate for any given well. For example, if Well A-3 were to leak at a rate of 100 BOPD, it would also produce over 100,000 gallons of formation water (brine) per day. If the flow was on the order of 1,000 BOPD (as Sun et al. suggest), the brine production rate would fill an Olympic size swimming pool within a matter of hours. Obviously, these flow rates are hypothetical and would be attenuated significantly by hydraulic losses attributable to the limited cross sectional area of the conductor and internal surface friction.

Based on the thermohaline density characteristics of the MC20 formation brines, a plume of produced brine fluid would become negatively buoyant within three meters of ascent above the mudline. This is because the fluid's high salinity offsets its non-conserved thermal buoyancy (i.e., becomes denser than ambient seawater as its heat is lost). This dynamic, coupled with the localized depression provided by this pit (> 6 meters deep), would lead to pooling of the dense brine fluids. This pooling effect would be self-reinforcing, because as new brine fluid percolates through the pool it would tend to conserve salinity, causing the pool to assume the salinity of the endmember reservoir (between 60‰ and 90‰).

The geometry of the resulting pool would potentially resemble naturally occurring brine pools associated with thermogenic hydrocarbon seeps and found throughout the Gulf of Mexico (fig 1). If we assume that the MC20 sheen source originates from a chronically leaking well, a persistent brine pool would be generated within the excavation pit, with the pit's recessed geometry acting to help shield the pool from mixing by the overlying water column currents. Within a period of months to a few years, various fauna would likely colonize the pool's edge, biologically generating carbonate (limestone) crusts and microbial mats and providing unmistakable evidence of active fluid flow from a hydrocarbon reservoir. To date, despite repeated ROV observations within the excavation pit, there has been no evidence of brine pools existing within the pit, indicating that wells with significant "water cuts" are not actively leaking.

Figure 1: photo of the edge of a seafloor brine pool generated by a naturally occurring hydrocarbon seep in the Gulf of Mexico. Various colonies of chemosynthetic organisms at the edge of the brine pool are visible in the foreground. The brine fluids are visible in the background.

Volumetric rate of gas production

In addition to formation water, each of the MC20 oil wells contains a natural gas component. The gas content of each well varies, with some having gas-to-oil (GOR) ratios that are in excess of the reservoir's gas solubility (R_s). By accounting for this R_s differential, in conjunction with temperature-dependent compressibility along the geothermal gradient of the vertical well bore, the volumetric flux rate of free gas from each well (as a function of oil leaking rate) can be calculated. Wells with GORs in excess of the R_s would yield free gas fluxes at rates that scale with the leaking oil. For example, if wells such as A-3 or A-8 were to leak with an oil release rate of 1000 BOPD, they would generate gas flow rates within the pit (accounting for ambient temperature and pressure) of approximately 150 liters per second. This translates to buoyancy generation at rates of 330 lbs/s, which would be sufficient to excavate sediments from within the pit down to the conductor source. Furthermore, if an ROV encountered this gas plume at the mudline, the lift provided by the gas plume would generate significant buoyancy , effecting the ROV's vertical control and be accelerated toward the surface. It is noteworthy that during the 2007 mass spectrometer survey this type of buoyancy transient occurred at the Plume A location, causing the work class ROV to lose vertical control.

Fluid velocity at conductor exit

By integrating the presumed oil flow rate with the associated brine and gas flow rates, an exit velocity can be calculated for each well at its conductor terminus. This exit velocity, which is based in part on the internal cross sectional area of the well conductor (2 3/8" diameter), is highly dependent on the produced brine "water cut" and GOR content. In the case of a leaking well with a GOR in significant excess of R_s and the dissolved gas exceeding the bubble point while still within the well bore, this would lead to a situation where the free gas would expand during ascent, resulting in an accelerating fluid flow. For example if Wells A3 or A8 were leaking at a rate of 1000 BOPD, this flow rate would require fluid velocities at the conductor exit faster than 450 m/s (over 1,000 mph). Again, this hypothetical scenario of a supersonic well fluid leak is unrealistic because it neglects the hydraulic losses attributable to the internal surface friction of the well bore, which would increase exponentially with velocity and lead to fluid compression, limiting the maximum fluid flow rate (oil, gas, and brine) from the well. Significant water cut and GOR values would tend to impede oil leakage rates because of the exponentially increasing hydraulic frictional losses that would need to be overcome (requiring exponentially higher reservoir pressures) in order to transport multiphase fluids containing significant brine and gas fractions. Thus, it is improbable that wells A3, A4, A7, A8, A10, A12, A12D, or A18 could individually sustain flow rates of hundreds of BOPD. Detailed analysis of reservoir fluid composition and hydraulic flow characteristics of the well and reservoir drive can reliably predict the upper bound (maximum possible) oil leak rate for any given MC20 well.

Thermal signature at the mudline

The reservoir fluids produced from each of the MC20 wells have a characteristic geothermal temperature associated with the well's production depth. This information, coupled with the geothermal gradient to the mudline, heat loss to the sediments, the fluid composition (including compressibility and specific heat) can be used to predict the temperature of well fluids at the mudline for any assumed flow rate. Restated algebraically, a wellhead thermal signature can be used to estimate the steady-state oil leakage rate from a well. If the ambient water temperature is known and a water column plume mixing model is applied, the thermal signature of the plume at a known distance from the mudline can be used to estimate the leak rate of a well. For example, the active well leak identified as plume "A" during the 2007 mass spectrometer survey recorded a temperature anomaly of 43° C at ≤1 meter above the mudline. During intervention well plugging, the source of this leak was later identified as being associated with well A-4. Using the previously described analytical methods, the thermal loss rates can be accounted for during fluid ascent while within the well pipe from the reservoir to the well deviation point and then through the shallow sediments (fig 2). Using a buoyancy-driven plume mixing model, the well's thermal signature can be plotted as a function of leakage rate and distance from the mudline. The 43° C intercept indicates that if Plume "A" was being generated by well A-4 during the 2007 survey, then its maximum possible leak rate would be ≤10 BOPD (fig 3). A modified form of this thermal analysis method can also be applied for each well to estimate the thermal signature for any hypothetical well leakage rate in the erosional pit area by accounting for the deviated conductor's thermal losses in the region from the former well bay [1] to the pit area.

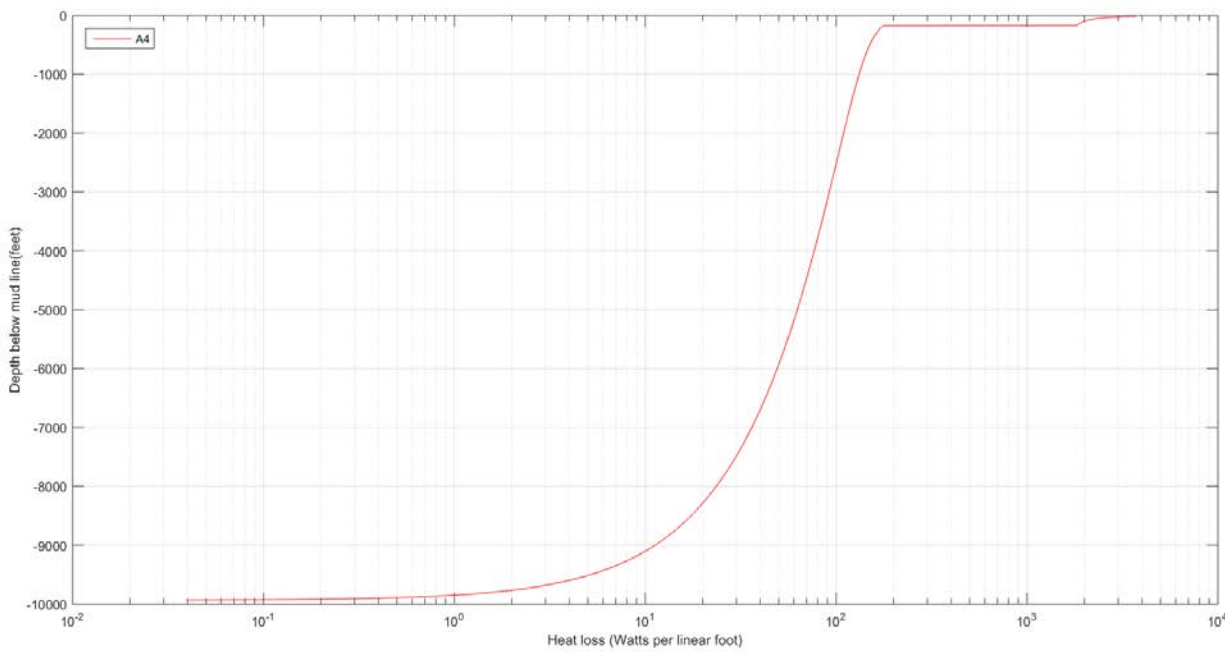

Figure 2: Plot of Well A-4 estimated thermal loss to the sediments as a function of depth below the mudline.

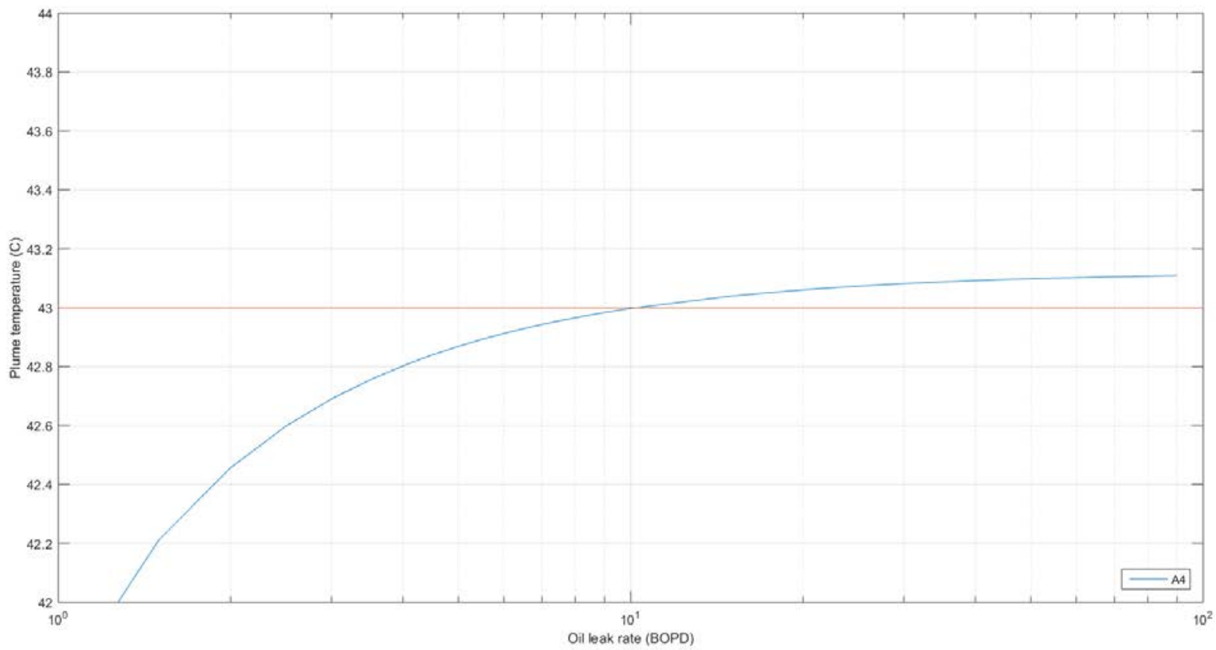

Figure 3: Estimate of 2007 Plume A size (maximum possible leakage rate) based on measured temperature within Plume A and the Well A-4 thermal signature.

Using this methodology, active well leak input to the erosional pit hydrocarbon plume can be quantified for each well. In December 2018 an ROV survey of the deepest 10 ft (3 meters) of the erosional pit indicated a minimum ambient water column temperature (while outside of the plume) of 18.82° C. The maximum temperature recorded by the ROV while it was within the plume in the erosional pit was 18.95° C at 1.5 m (4.92 ft) altitude above the mudline (fig 4). Assuming that this temperature differential is entirely attributable to a leaking well (i.e., no temporal variability in water column temperature and no self-heating caused by the ROV's lights or hydraulic power unit) the flow rate-dependent thermal signature curve of each well can be used to calculate the possible maximum contribution from each of the oil wells (fig 5). Thermal signature curves indicate that a well leak with this thermal signature would be between 0.015 and 1.5 BOPD (0.6 to 63 gallons/day), see Table 1. If the leak originated exclusively from Well A-24 (the well with the most subtle thermal signature) this would represent the maximum possible leak rate of <1.5 BOPD. If multiple wells were contributing to the leak, the composite thermal signature would be a linearly weighted average of the well contributions. Thus the erosional pit plume measured temperature indicates that the worst-case leak at that time was < 1.5 BOPD.

This estimate does not take into account whether the well is capable of flowing (i.e., if there is sufficient reservoir pressure, or if the well has been plugged). Review of the potential for flow from each well will cause several of these calculated maxima to be rejected as highly improbable.

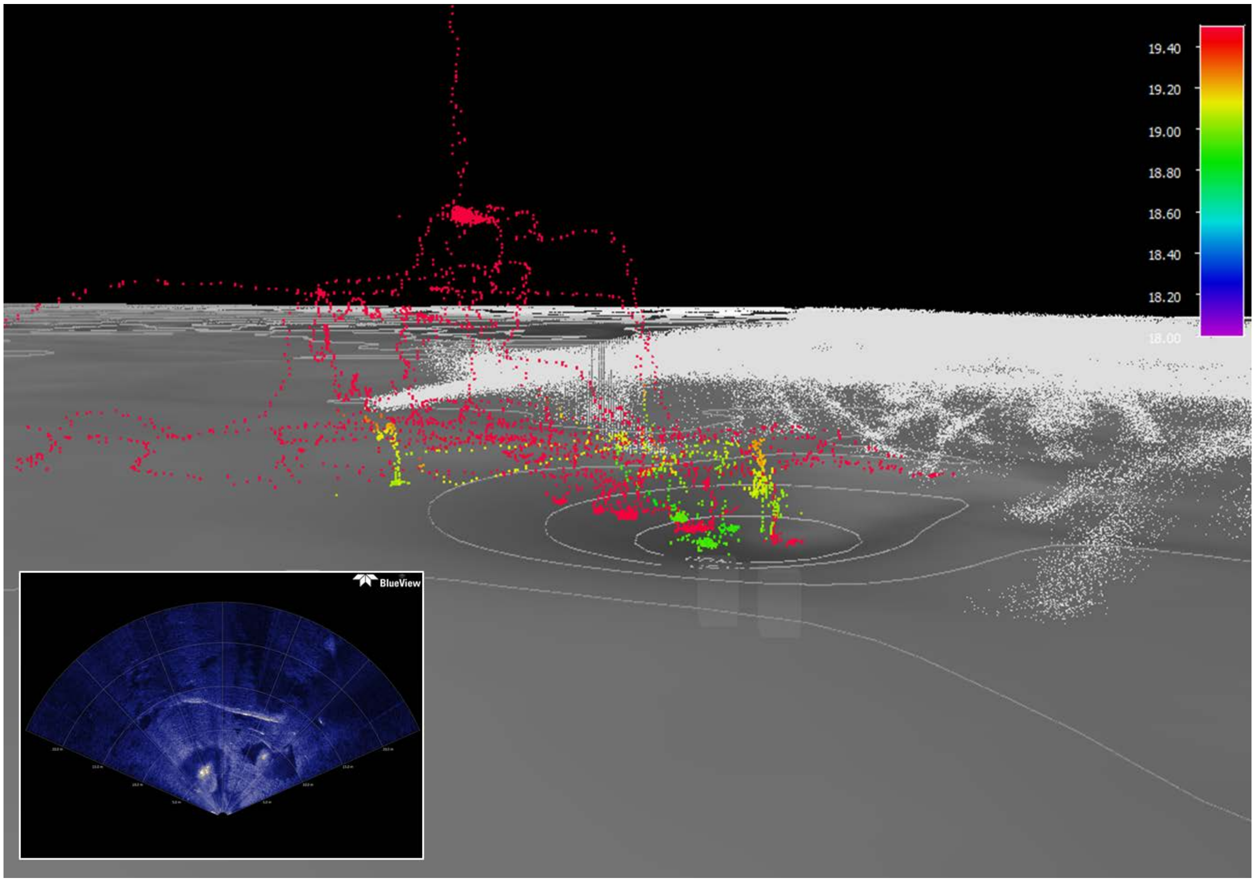

Figure 4: 3D reconstruction of water column temperature record observed during December 2018 ROV survey; viewing perspective is from the west looking east with a vertical exaggeration of 3X. The lowest temperature values were recorded within the erosional pit. Containment dome C & D locations are expressed as faint gray cube shapes below the mudline. Each containment dome is 10 ft by 10 ft. The toppled jacket structure is shown as a point cloud in white. Data describing the jacket structure and ocean floor bathymetry is from the 2017 SSLWG survey [1]. The inset at lower left is a BlueView sonar screen shot recorded by the ROV during the Dec 2018 survey above the erosional pit before the ROV descended into the pit. Bright colors indicate high amplitude acoustic contacts. The linear feature at a distance of between 10 and 15 meters corresponds to the jacket structure. The two high amplitude contacts at ranges of between 5 and 10 meters correlate with the positions of containment domes C & D.

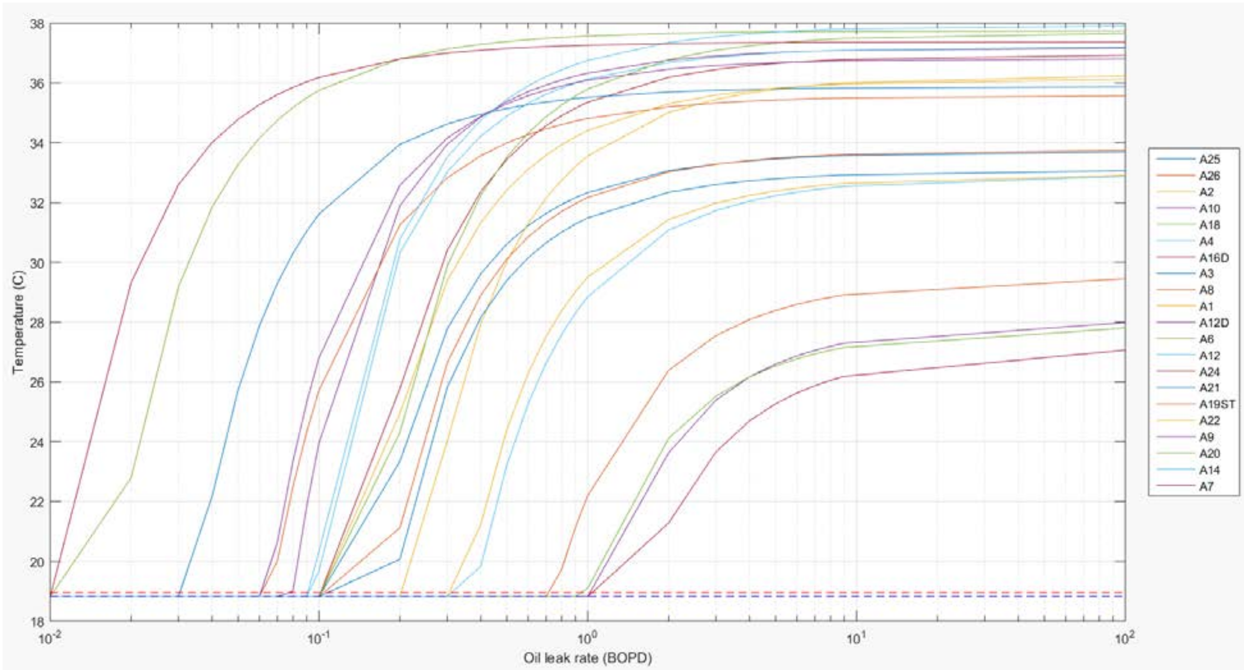

Figure 5: Graph of calculated thermal signatures for each MC20 oil well, showing the plume's thermal signature for flow rates between 0.01 and 100 BOPD at 1.5 meters distance from the mudline source. The horizontal dashed blue line indicates the measured ambient water column temperature, and the horizontal dashed red line indicates the maximum measured plume temperature at 1.5 meters above the source. The intercept of the plume temperature (dashed red) line with a well thermal signature curve indicates the maximum possible flow from that well, assuming that the well is responsible for the entire thermal signature (i.e., is responsible for the entire leak).

Table 1: Calculated maximum possible leak rate for each well using thermal signature analysis.

Well	Maximum possible leak rate
A1	<0.16
A2	<0.21
A3	<0.035
A4	<0.095
A6	<0.18
A7	<0.015
A8	<0.065
A9	< 1.1
A10	<0.080
A12	<0.095
A12D	<0.065
A14	<0.35
A16D	<0.15
A18	<0.02
A19ST	<0.19
A20	<0.95
A21	<0.2
A22	<0.35
A24	< 1.5
A25	<0.18
A26	<0.75

Salinity signature at the mudline

Similar to the well thermal signature analysis, it is possible to establish an upper bound of possible well leak rate by modeling the salinity signature of the plume as a function of flow rate and dilution of a well's characteristic produced water salinity. Unlike the thermal signature of a flowing well, which is not a conserved tracer (due to heat losses through the well casing and sediments), a flowing well's salinity signature is conserved during transport through the well bore from the reservoir. It is only once the produced water leaves the conductor and mixes with sediment pore water and the overlying water column that it is diluted.

Examination of ROV-measured salinity data recorded during December 2018 ROV survey, reveals that when the ROV was positioned to record data in the erosional pit plume, the recorded salinity values were slightly below ambient, with minimum values decreasing to 34.62 PSU at 0.33 m (1.1 ft) altitude above the source, despite ambient water column salinity being 36.66 PSU (figs 6&7). This 2.04 PSU salinity decrease provides strong evidence that the plume is not being generated by wells leaking fluids from a MC20 production reservoir, and suggests that the plume may be driven by a shallower source/sources containing brackish groundwater and free gas. These depressed salinity values also suggest that the source fluids have a positive buoyancy, which would tend to destabilize sediments in the region around the plume source, enhancing erosion of the sediments. Prior geotechnical surveys of the MC20 site have identified shallow gas-bearing strata and freshwater plumes emanating from the seafloor.

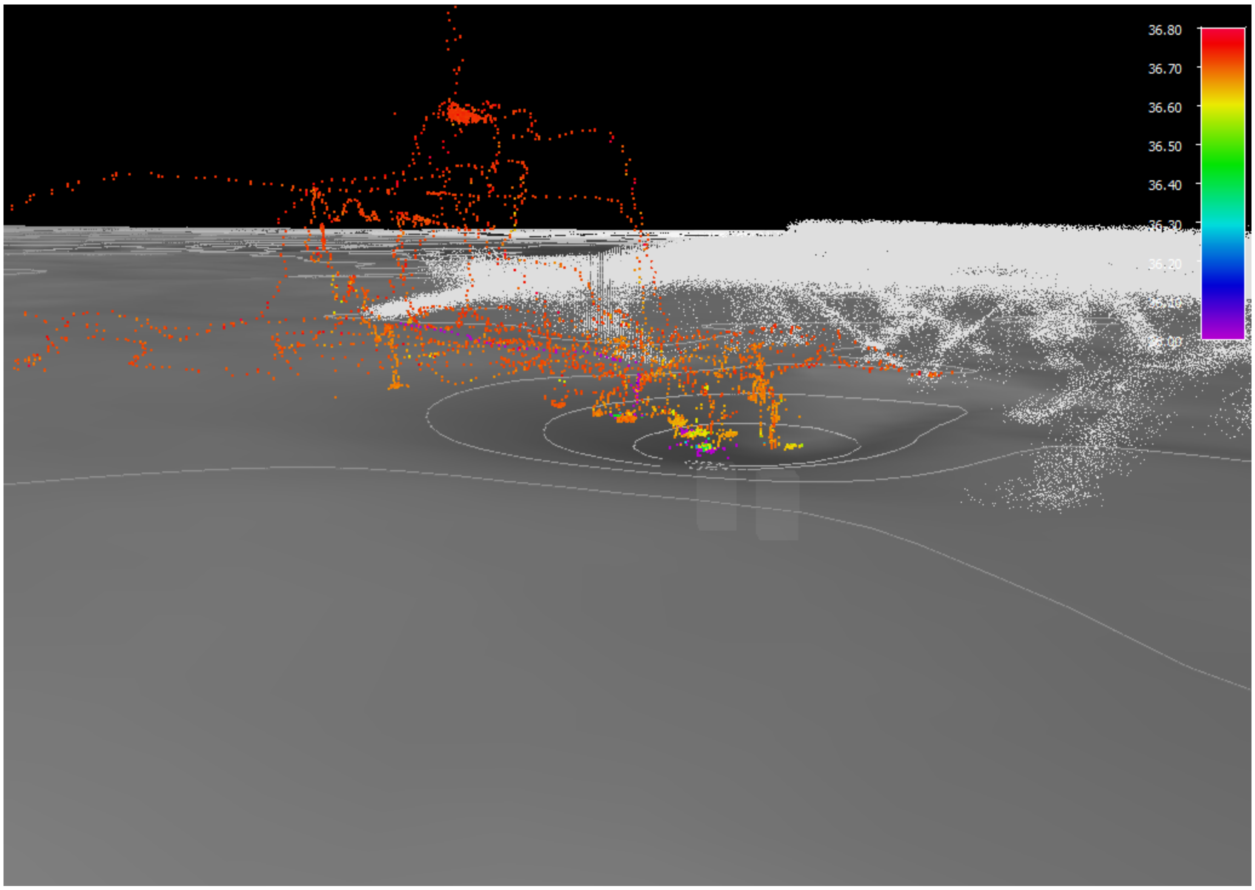

Figure 6: 3D reconstruction of water column salinity record, viewing perspective is from the west looking east. The toppled jacket structure is shown in white. With the exception of brackish water measured near the surface, the lowest salinity values were recorded within the erosional pit. Dome C&D locations are expressed as faint gray cube shapes below the mudline.

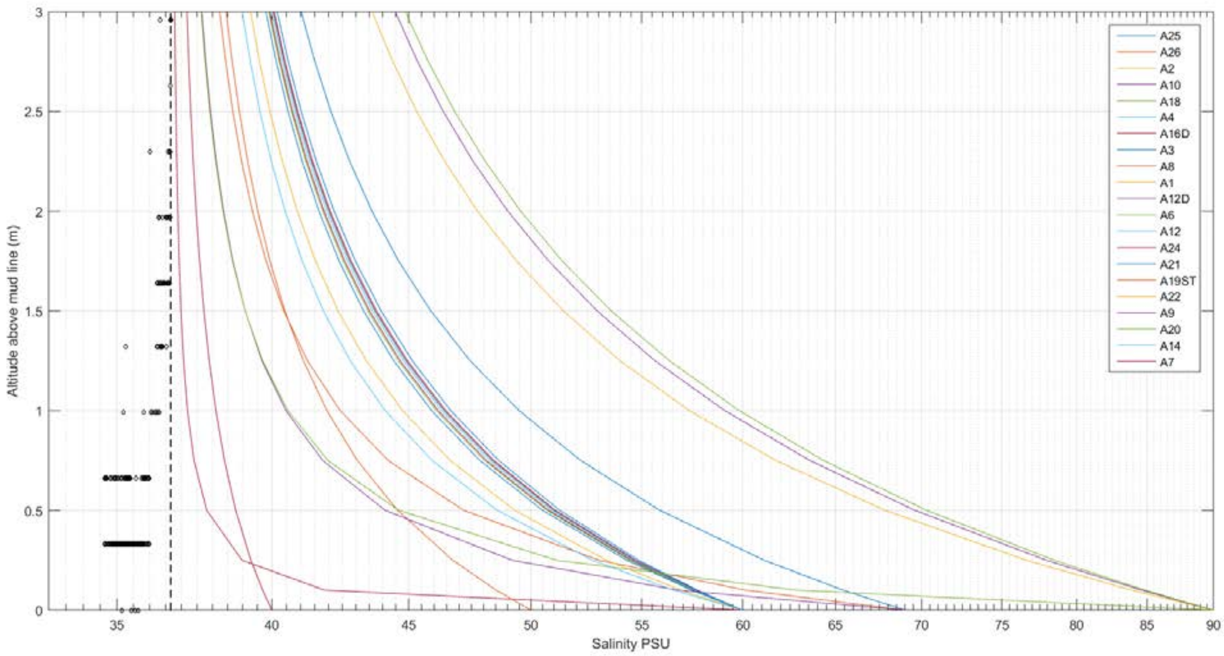

Figure 7: Graph of calculated plume salinity as a function of the well salinity signature and distance from the source. Vertical black dashed line indicates the ambient water column salinity, black diamonds describe in-situ salinity measurements at varying altitudes within the plume.

Summary

Results from the preceding analyses indicate that many of the wells have limited potential for oil leakage because of large hydraulic losses resulting from high water and gas content. Furthermore, if any of the high water cut wells were to leak, they would generate a telltale brine pool within the erosional pit. This consideration is important for understanding the potential maximum leakage rate for wells where plugging with intervention wells has not been attempted. In particular, Wells A-3 and A-8 (which have been the subject of repeated speculation as possible leak sources) would be incapable of generating oil leaks of hundreds to thousands of BOPD, and would generate brine pools at even modest leak rates. Other MC20 wells, including A4, A7, A10, A12, A12D, or A18 would be similarly limited by internal hydraulic frictional losses to worst case scenario leaks of significantly less than 100 BOPD. If P&A status is considered, along with well state (e.g., naturally plugged by sanding in or other circumstances), the list of wells that could plausibly generate flows in excess of 100 BOPD would be further reduced.

In contrast to the high temperature oil plume (26° C above ambient) identified in 2007, the 2018 erosional pit plume’s temperature signature is 200X smaller (0.13° C above ambient). These low values are consistent with the recent findings of the NOAA technical memorandum [2], which states in section 2.3.2 that, “temperatures values did not show significant excursions from ambient values."

This limited heat flow constrains the maximum possible leak rate (for all wells combined) to less than 1.5 BOPD (63 gallons/day). Of all the MC20 wells, only A-24 and A-9 could in theory generate a leak in excess of 1 BOPD with the observed thermal signature. However, reservoir analysis must also be considered to determine if reservoir conditions enable oil outflow to these wells. Furthermore, plume salinity measurements that were recorded simultaneously with temperature show that the plume's salinity was actually below ambient water column levels. This is also corroborated in the NOAA technical Memorandum [2], which states that negative salinity values recorded during that survey operation "indicate an ongoing discharge of lower salinity water emanating from the ocean floor and localized to the region above the conductor bundle". Given that all of the MC20 oil reservoirs contain brine fluids that are roughly 2 to 3 times more salty than ambient seawater, the observed plume salinity provides direct evidence that none of the MC 20 production reservoirs are leaking at measureable rates. The plume's negligible temperature signature and decreased salinity suggest that it is instead being generated by a shallower low-temperature fluid source (containing gas and brackish water) that may be migrating along/through one or more of the conductors.

References:

1. Camilli, R., *Spring 2017 Acoustic Survey Operations, Results, and Interpretations*, in *Sheen Source Location Working Group Final Report* 2017. p. 89.
2. Mason, A.L., *An Integrated Assessment of Oil and Gas Release into the Marine Environment at the Former Taylor Energy MC20 Site.* 2019.